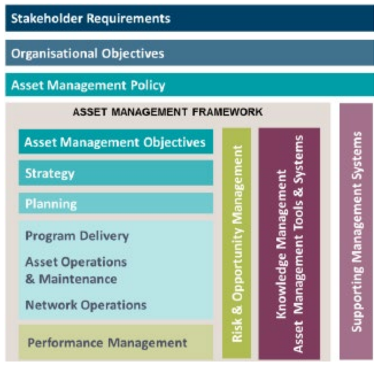
Protection Design

Guidelines



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Contents

Revision Details

Version	Date	Summary of change	Section
0	10 Jun 2016	Original. First Issue of the consolidated set of Automation & Control Guidelines	
0.1	16 Jan 2017	Entire document has been reformatted.	
1	10 Apr 2017	Inclusion of Chapter: Supporting Documentation – Demonstration of Protection Compliance	
2	08 Jun 2018	2018 Review.	
3	10 Jan 2020	2020 Review.	
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5	22 Mar 2024	Reformatted and prepared for external release.	

1 Introduction

1.1 Purpose and Scope

The purpose of these guidelines are to:

1) Define the high level functional requirements for the protection systems used in Western Power's terminal stations and zone substations; and

2) Capture information which explains the reasoning behind the protection philosophy, design and settings adopted on Western Power's South West interconnected system (SWIS).

1.2 General Compliance Requirements

In general, the protection systems employed on the SWIS shall comply with the Technical Rules, Western Power specific requirements and good electrical industry practices.

All protection designs must meet the requirements outlined in Section 2 – Protection Philosophy and Performance Criteria.

Specialised requirements that are pertinent to specific protection systems are called out in the relevant sections.

1.3 Availability of Internal Documentation

Some portions of this document are available to accredited vendors.

1.4 Abbreviations

Table 1.1 – Abbreviations

Abbreviation	Meaning
CMS	Customer main switch.
DAR	Delayed auto reclose
DMT	Definite minimum time
ET	Earthing Transformer
HSSPAR	High speed single pole auto reclose
IDMT	Inverse definite minimum time
NPS	Negative phase sequence
PU	Pickup
pu	Per unit
SIR	System impedance ratio
TMS	Time multiplier setting
TPES	Transmission protection equipment system.

1.5 Definitions

Table 1.2 – Definitions

Term	Definition
Actual turns ratio	The turns ratio modified to account for line to phase transformations of currents and voltages between transformer windings in three phase systems.
Additional function	Additional functions may be required for specific applications. Additional functions are not listed in this guideline.
Adjacent feeder	A feeder that is directly connected or indirectly connected to the same busbar as a distribution connected generator
Adjacent line	A line extending from a busbar connected to a protected line.
Aided tripping	Aided tripping is a historical term. Protection schemes can aid, or speed up, tripping by sending permissive signals or removing blocking signals.
Apparent differential current	Differential current which is not caused by a fault in the operating zone.
Bus coupler	A bus coupler circuit comprises a circuit breaker, associated disconnector(s) and associated current transformers. Bus couplers are used to sectionalise busbars in parallel.
Bus Section	A bus section circuit comprises a circuit breaker, associated disconnector(s) and associated current transformers. Bus sections are used to sectionalise busbars in series.
Circuit breaker break time	Interval of time between the beginning of the opening time of a mechanical switching device and the end of the arcing time (defined in AS 62271 – 100 2008, definition 3.7.135 p.17)
Circuit breaker opening time	The interval of time between the instant of energising the opening release, the circuit breaker being in the closed position, and the instant when the arcing contacts have separated in all poles (defined in AS 62271 – 100 2008, definition 3.7.133 p.16).
Data display units	A display panel which when connected to the RTU is able to display SCADA status and analogue points. The panel can have configurable displays showing alarms, metering and status indications. A data display panel has the ability to maintain fleeting alarms. It does not, however, time stamp events.
Dead time	The time between the circuit breaker trip and reclose.
Dedicated generator feeder	Dedicated generator feeders have no additional customers connected to the generator feeder
Discrimination	The selective tripping of only those circuit breakers required to clear a fault with a minimum loss of load
Distribution Voltage	6.6 kV, 11 kV, 22 kV, 33 kV
Downstream	Away from the source
Earth fault relay	Historical term used to describe a relay that detects zero sequence currents

Term	Definition
Effectively earthed neutral system	System earthed through a sufficiently low impedance such that for all system conditions the ratio of the zero sequence reactance to the positive sequence reactance (X_0 / X_1) is positive and less that 3 and the ratio of the zero sequence resistance to the positive sequence reactance (R_0 / X_1) is positive and less than 1. Normally solidly earthed neutral systems or low impedance earthed neutral systems (defined in AS 62271 – 100 2008, definition 3.7.128 p.7). Refer to Section 6.4.1.2.6 for further explanation.
Evolving fault	An evolving fault is usually defined as one which changes its configuration from one fault type to another fault type (e.g. a ph-E fault to a multiphase fault).
Feeder	A conductor on the distribution system supplying power to a specified area. Includes any equipment attached at the feeder voltage from the zone substation circuit breaker up to and including the distribution transformer HV bushings.
Finish wire	The last wire in the TCS looping. The last wire terminating on the TCS element is always a finish wire. The wire on the last terminal in the protection cubicle before the supply goes out to the circuit breaker is a finish wire. A finish wire must always have an associated start wire.
Generator feeder	A distribution system feeder to which a generator is connected.
Generator interconnection	The circuit extending from the Western Power zone substation or terminal yard to the generator site. This will typically be a distribution feeder or transmission line circuit.
Grading	Delaying the operation of successive upstream protection systems to allow discrimination
Grading margin	The time interval between operation of the major and minor relays.
High voltage (HV)	The Technical Rules define high voltage as ‘any nominal voltage above 1 kV’. However, when used in protection standards and guidelines, high voltage (HV) is defined as the rated voltage of the high voltage winding of the power transformer (as defined in 3.3.4 of AS 60076.1 – 2005).
Human machine interface (HMI)	A computer providing an electronic MIMIC panel. The HMI provides a substation single line diagram showing layout and current configuration yard. The HMI also provides local control, indication, alarms, isolation and metering functions. All data is received and sent through the RTU.
Interlocked	The protection scheme at one end of a line trips and sends a permissive signal or removes a block signal to the other end.
Interconnected system	A system of lines and substations with multiple sources
Large generator	For the purposes of this guideline, a large generator refers to a generator with aggregate rated capacity ≥ 10 MW
Load encroachment	The distance relay will detect load as impedance with an angle typically ±40 degrees from the R-axis. The angle is settable in the relay. If the load is large enough it may appear as a fault within the distance characteristic operating zone.

Term	Definition
Local / Remote	For the purpose of the circuit breaker, local means at the circuit breaker and remote means either at the protection panel or EPCC. For the purpose of protection operation and indication, local means at the protection panel (or relay) and remote means EPCC. Local backup is a form of backup protection located at the same site as the protection it is backing up. The transformer LV backing up the feeder main protection system is an example of a type of local backup protection. Remote backup is a form of backup protection located a site remote to the protection it is backing up. Distance protection is an example of a protection that can provide remote backup.
Local faults	Faults are considered local when they are within the same substation as the circuit breaker For 2-terminal lines faults are considered local when it is on the first 50% of impedance from a substation providing they can be cleared by a circuit breaker in the local substation For lines with more than 2 terminals faults are considered local providing a circuit breaker in the local substation is used in the fault clearance and: 1. Fault is on the same line section as the local substation containing the circuit breaker or 2. Fault is within 50% of the shortest line impedance between the end in question and the remote ends All other faults are considered remote faults
Low level fault	Faults that result in short circuit currents that are relatively small and are comparable with load currents.
Low voltage (LV)	The Technical Rules define low voltage as 'any nominal voltage of 1 kV and below'. However, for the purpose of protection standards and guidelines, low voltage (LV) is defined as the rated voltage of the low voltage winding of the power transformer (as defined in 3.3.5 of AS 60076.1 – 2005).
Major protection system	The first upstream protection system from the minor protection system. Power flows from the major relay location to the minor relay location.
Mimic	A hardwired panel providing a single line diagram of the substation. It provides a single point for local control and metering of the various circuits in the substation.
Minimum fault current (I_{K_MIN})	The fault current under minimum system conditions or abnormal equipment conditions at the point of interest for the type of fault being considered.
Minor protection system	The first upstream protection system from a fault.
Non-dedicated generator feeder	Non-dedicated generator feeders have additional customers connected to the generator feeder circuit. This includes generator feeders with and without reclosers.
Operating Voltage (V_{OP})	In voltage measuring high impedance schemes V_{OP} is the voltage developed across the relay element. In current measuring high impedance schemes it is the voltage developed across the stabilising resistor
Operating zone	The portion of the protected circuit for which, when faulted, the main protection system or second protection system is intended to operate.
Overcurrent relay	Historical term used to describe a relay that is used to detect positive and negative sequence currents. In practice they also detect zero sequence currents.

Term	Definition
Primary operate current (POC)	For feeder protection this is the minimum nominal current at which a protection scheme begins to operate. This is the primary amp pickup current requested by the distribution engineer. In high impedance schemes this is the sum of the secondary currents in a high impedance scheme. This includes the relay operating current, the metrosil current, the CT magnetising current, the stabilising resistor current and the CT supervision current (if fitted). The primary operate current of a drop out fuse is the current on the total clearing time-current characteristic curve corresponding to 100 seconds. The primary operate current of a high rupture capacity fuse is the specified critical current.
Primary winding (instrument transformers)	The primary winding of a CT is the winding connected to the system. The primary winding of an IPCT is the winding connected to the main CT. The primary winding of a VT is the winding connected to the system.
Primary winding (power transformer)	Highest voltage winding with larger MVA rating. The source is connected to the primary winding.
Protected line	The transmission line which the main protection system is designed to protect.
Protection operate time	The time it takes for a protection scheme to detect a fault and send a trip signal. This includes any trip relays included in the scheme.
Protection 1	Protection scheme supplied by battery 1
Protection 2	Protection scheme supplied by battery 2
Protection sensitivity factor – target (K_{PSFT})	A target which the sensitivity performance of the protection system is measured against.
Protection sensitivity factor – calculated (K_{PSFC})	The ratio of the protection operating point of an overcurrent protection scheme to the minimum fault current for the type of fault being considered.
Protection sensitivity performance (P_{SP})	An indicator of the sensitivity of an overcurrent protection scheme with respect to the protection sensitivity factor – target (K_{PSFT}) $P_{SP} = (K_{PSFT} – K_{PSFC}) / K_{PSFT} \times 100\%$
Radial system	Supplied from only 1 source
Ring system	A circuit consisting of several substations starting and finishing at the same busbar
Reactor	The technical definition of a reactor is any device introducing reactance to an electric circuit. This definition includes both capacitors and inductors. The Technical Rules and Western Powers use of the word limits the definition of a reactor to include inductors only.
Reclaim time / reset time	The reclaim time is the period during which the automatic reclose function decides if the fault is permanent or transient. If the fault is present during the reclaim time the fault is considered permanent. If the fault is absent for the duration of the reclaim time, the fault is considered transient. The reclaim time must e long enough to: Allow the protection to operate for a permanent fault Allow the circuit breaker enough time to be ready for another reclose.
Remote faults	All faults that are not local faults

Term	Definition
SCADA device	A device that incorporates remote metering and / or other SCADA functions. A protection relay used to send alarms and indication to the RTU is a SCADA device.
Secondary Turns ratio (n) [1]	$\text{Turns Ratio} = n = \frac{V_{1\_phase}}{V_{2\_phase}} = \frac{N_1}{N_2} = \frac{I_{2\_phase}}{I_{1\_phase}}$ (N_1 depends on the tap)
Secondary winding (instrument transformers)	The secondary winding of a CT is connected to the metering or protection circuit. The secondary winding of an IPCT is connected to the metering or protection relay. The secondary winding of a VT is connected to the metering or protection circuit
Secondary winding (power transformer)	Lower voltage winding with MVA rating equal or close to HV winding. Load is connected to the secondary winding (e.g. other terminal stations, zone substations, or distribution feeders and capacitors).
Sensitivity	A general term that refers to the ability of a protection system to detect worst case fault conditions in the operating zone. The sensitivity of an over current protection scheme is the lowest pickup current, in primary amps, that will guarantee tripping.
Single pole tripping	Each pole of the circuit breaker receives a separate trip signal.
Site specific functions	Site specific functions are included in a design when the protection design engineer determines that they are required.
Small generator	A generator with aggregate rated capacity ≥ 30 kVA and <10 MW.
Small zone fault	A fault which occurs on an area of equipment that is within the zone of detection of a protection scheme, but for which not all contributions to the fault will be cleared by the circuit breaker(s) tripped by that protection scheme. For example, a fault in the area of equipment between a current transformer and a circuit breaker, fed from the current transformer side, may be a small zone fault.
Stabilising resistor	The purpose of a stabilising resistor is to adjust the operating voltage to prevent incorrect operation for through faults due to CT saturation. In current measuring schemes, the stabilising resistor is wired series with the relay element. In voltage measuring schemes the stabilising resistor is wired in parallel with the relay element.
Standard functions	Standard functions are included in all circuit specific designs. This allows for the standardisation of setting orders.
Start wire	The first wire in the TCS looping. The first wire coming out of the supply fuse is always a start wire. A start wire must always have an associated finish wire
System backup protection	A backup protection not required by the Technical Rules but one that is often implemented because it can be done so at minimal additional cost (e.g. time stepped distance implemented in a digital differential scheme).
System impedance ratio (SIR)	The source impedance divided by the line impedance.
Terminal station	The Technical Rules define a terminal station as ‘a substation that transforms electricity between two transmission voltages and which supplies electricity to zone substations but which does not supply electricity to the distribution system’. For the purposes of this guideline, a substation which does not transform but does switch transmission voltages is also included in the definition

[1] The secondary and tertiary windings have a fixed number of turns. Their corresponding line voltages are shown on the rating plate. The primary tap changer adjusts both the tertiary and secondary voltages, and therefore both the tertiary and secondary turns ratios, simultaneously.

Term	Definition
Tertiary voltage (TV)	For the purposes of this guideline, tertiary voltage (TV) is defined as the rated voltage of the tertiary winding of the power transformer.
Tertiary winding (power transformer)	Lower voltage winding used for flux equalization and, if brought out, has the lowest MVA rating. Load may be connected to the tertiary winding if it is brought out (e.g. capacitors, reactors, and station supplies).
Three pole tripping	All three poles of a circuit breaker receive the same trip signal
Transient recovery voltage (TRV)	The voltage that appears across the circuit breaker terminals after current interruption.
Transmission Line	The Technical rules define a transmission line as 'a power line that is part of the transmission system'. For the purposes of this guideline, the definition of transmission line also includes power cables in the transmission system
Tertiary turns ratio (n_T) [2]	$\text{Tertiary Turns Ratio} = n_T = \frac{V_{1\_\text{phase}}}{V_{T\_\text{phase}}} = \frac{N_1}{N_T} = \frac{I_{T\_\text{phase}}}{I_{1\_\text{phase}}}$ (N_1 depends on the tap)
Transmission Voltage	66 kV, 132 kV, 220 kV, 330 kV
Upstream	Towards the source
Variable Shunt Reactor	A type of shunt reactor that has an adjustable rating
Weak Infeed	A weak infeed situation occurs when the fault contribution to a line fault from a particular substation is small or close to zero. In this situation, the line protection may not be able to clear the weak infeed within Technical Rules clearance times

[2] The secondary and tertiary windings have a fixed number of turns. Their corresponding line voltages are shown on the rating plate. The primary tap changer adjusts both the tertiary and secondary voltages, and therefore both the tertiary and secondary turns ratios, simultaneously.

1.6 References

1.7 Legacy Documents

2 Protection Philosophy and Performance Criteria

2.1 Introduction

The purposes of this section are to:

1) Define at a high level the protection philosophy and performance criteria for protection systems used at Western Power terminal stations and zone substations.
2) Capture information which explains the reasoning behind protection philosophy adopted on Western Power's South West interconnected system (SWIS).

2.2 Scope

This section applies to transmission and distribution circuits either within or connected between a Western Power terminal or zone substation. It does not include generation or distribution systems.

2.3 Functional Requirements

The functional requirements for protection systems are:

1) Detect and clear faults in the operating zone.
2) Detect and clear faults within times specified by the Technical Rules.
3) Coordinate with upstream and downstream protection systems.
4) Provide backup for downstream protection systems.
5) Clear faults within the thermal limits of associated primary equipment, including the power transformer.

2.4 Protection Philosophy

Western Power's philosophy of protection is based on the fact that any single contingency shall not affect the performance of protection. This contingency could be:

1) Non availability of one item of primary equipment
2) Non availability of one item secondary equipment. Examples include:
    a) Battery supply
    b) Protection relay
    c) Circuit breaker trip coil
    d) CT or VT secondary core
    e) Tele-protection signalling channel

2.5 Protection Performance Criteria

The Technical Rules outline the performance criteria that must be met by protection systems installed on the SWIS. The purpose of this section is to clarify ambiguities in the Technical Rules.

2.5.1 General Requirements

2.5.1.1 Discrimination [3]

A fault must be cleared by the minimum number of circuit breakers for all systems stronger than or equal to the minimum system condition. Only the faulted plant can be removed from service. This applies for any single secondary or primary equipment contingency for voltages above 33 kV [4].

Discrimination for single contingency secondary outages is not required at voltages of 33 kV and below

A circuit breaker failure (CB Fail) event shall not result in more than two major primary equipment items being removed from service at voltages of 220 kV and above. Examples of major primary equipment include lines, transformers and busbars. Backup protection is therefore required to coordinate with CB Fail protection.

A circuit breaker failure (CB Fail) event may result in more than two major primary equipment items being removed from service at voltages of 132 kV and below. Western Power accepts this could result in complete loss of a terminal station or zone substation. Remote backup protection for a circuit breaker failure is therefore acceptable.

2.5.1.2 Approved Protection Relays [5]

The main protection system and backup protection system relays shall:

1) Be purchased from recognised manufacturers of protection relays
2) Comply with IEC 60255
3) Be tested upon delivery to verify the manufacturer’s declared performance and any additional Western Power requirements.
4) Numerical relays must have protection defective and device defective alarms capable of being hardwired directly to a remote device (e.g. RTU or gateway).
5) Miniature circuit breakers (MCB) must have local and remote indication for an operation.

2.5.2 Duplication of Protection

2.5.2.1 Number of Protections Required [6]

The number of protections that must be employed to protect a circuit on the SWIS is dependent on the nominal voltage of the circuit that is faulted.

Table 2.1 summarises the number of protections required for circuits of different voltages.

Table 2.1 – Number of protections required by voltage level

Voltage Level	Main Protection 1	Main Protection 2	Backup Protection 1	Backup Protection 2
220 kV and above	Yes	Yes	Yes	Yes
66 kV and 132 kV	Yes	Yes	Yes	Small zone faults only

[3] Technical Rules section 2.9.1(b)
[4] Technical Rules clause 2.9.2(a)(1)
[5] Technical Rules clause 2.9.1(c)
[6] Technical Rules section 2.9.2

33 kV and below	Yes	Only if CFCT present	No	Yes [7]

Two local backup protection systems are required for primary equipment operating at 220 kV and above. This is because discrimination of local backup protection systems is required. Discrimination is required because Western Power does not accept a 330 kV terminal station being blacked out by a remote backup operation to clear a small zone fault.

One local backup protection system is required for primary equipment operating at 66 kV or 132 kV. The local backup system operates for circuit breaker failure. There is also a remote backup in the form of a zone 2 distance reach to clear small zone faults [8]. Western Power accepts a remote backup operation resulting in blacking out a substation if the local backup system fails.

While not required by the Technical Rules, duplicated local backup protection is preferred at 66 kV and 132 kV where duplicated communications channels are present. This has the following advantages:

1) Reduces reliance on general system backup by ensuring circuit breaker failure is initiated on the circuit breaker being tripped.
2) Reduces the chance of blacking out a terminal station or zone substation for a remote backup operation.
3) Caters for a circuit breaker failure coupled with a battery or relay failure.

2.5.2.2 System Backup Protection

System backup protection does not have to be included in every protection scheme. However each item of primary equipment must be included within the operating zone of at least one backup protection scheme (which could be provided by system backup protection). The following are examples of system backup:

1) Time stepped distance elements within digital differential protection relays. When possible, all digital differential relays used to protect transmission line circuits shall have backup distance elements enabled. This provides some level of protection should the quality of both independent communications bearers diminish. This also provides an additional option to protect a circuit should a single communications service be out of service for more than 48 hours (i.e. zone 2 timer can be reduced to zero if CFCT present). Consecutive lines using double unit protections with no backup distance protection available shall be avoided.
2) Overcurrent elements within numerical relays. Numerical relays shall be equipped with backup overcurrent protection. [9] Backup overcurrent provides some degree of protection should a communications service or voltage transformer be out of service. Non-directional IDMT relays shall be included in the backup protection 2 of all transformer HV circuits.
3) The Technical Rules requires that at least one of the main protection schemes on a transmission circuit contain earth fault protection [10]. To ensure consistency of setting, IDMT earth fault protection shall be provided by both protection schemes protecting transmission circuits.

System backup protection has no specified operating time requirement. Typically 2.5 seconds is expected. System backup protection should be coordinated with other protection systems where useful discrimination can be achieved; however, this is not an essential element of the protection. Sequential tripping may be necessary to clear a fault.

[7] The backup is indicated as protection 2, due to the fact that it must be completely independent of the main protection (which is supplied from battery 1).
[8] Technical Rules clause 2.9.2(a)2
[9] While the relay must have this facility, enabling the function is a site specific requirement.
[10] Technical Rules clause 2.9.2(a)1

2.5.2.3 Redundancy

Two fully independent schemes of differing principle are required to guard against common mode failure. Western Power may require a User to demonstrate that the Users protection schemes do not have a possibility of common mode failure.

2.5.2.3.1 Two Fully Independent Schemes

A single piece of Primary Equipment meets the requirement for two independent protection schemes under the following conditions:

1) The circuit breaker has two independent tripping circuits. This is contingent on both protection schemes providing circuit breaker failure.
2) The current transformer and voltage transformer has two independent secondary windings
3) Separate auxiliary supplies, signalling systems, cabling and wiring

2.5.2.3.2 Differing Principle

Western Power considers that the following relay variations satisfy the requirement for different operating principles:

1) Different manufacturers with different hardware and different algorithms. Western Power's approved relays shall meet this criterion.
2) Same manufacture with different hardware and different algorithms. There must be no common mode of failure (e.g. different power supplies, inputs, outputs, CPU, etc.).

2.5.2.3.3 Unwanted Operations

Redundancy (to cater for secondary equipment failures that result in an unwanted operation) is required for known problems which cause an unacceptable loss of security. An example is a double busbar configuration with a switched CT busbar protection scheme. There must be a means to prevent tripping of the protection scheme for failure of the auxiliary contacts associated with the busbar selection disconnector. This may take the form of CT supervision or a redundant 'two out of two' protection scheme.

2.5.3 Availability of Protection Systems

It is acceptable to keep a circuit operational with a main or backup protection scheme out of service for up to 48 hours [11] without modifying the remaining protection systems. This is acceptable because of the low probability of a second contingency during this 48 hour window.

A fault is not considered a contingency.

A second contingency is considered credible when the 48 hours has expired and the failed element has not been reinstated.

There are three scenarios to consider. These scenarios have different probabilities of occurrence. The scenarios, in order of decreasing probability, are outlined in Table 2.2:

[11] Technical Rules, section 2.9.3

Table 2.2 – Second contingency scenarios

Scenario	First Contingency	Second Contingency (after 48 hours)	Fault
1	CB Fail protection	Circuit breaker fails	Primary equipment fault
2	Main protection scheme 1 failure	Main protection scheme 2 failure	Primary equipment fault
3	Backup protection scheme 1 failure	Backup protection scheme 2 failure	Small zone fault

Scenario 3 is considered highly improbable but the consequences are extreme, especially for the 330 kV system.

The consequence for all scenarios is that the fault has to be cleared by remote backup protection systems. This remote clearance will be slow or, in rare circumstances, the fault may not be detected.

System management is responsible for deciding what action to take when a protection scheme is out of service for longer than 48 hours. Protection & Automation are responsible for:

1) Providing the probability and consequences of an extended outage.

2) Provide information on temporary actions that may be taken to cater for the second contingency to help system management reach a decision.

3) Develop a contingency plan when requested.

2.5.4 Maximum Total Fault Clearance Time

The Technical Rules define the maximum total fault clearance times that must be met for zero impedance faults on the South West Interconnected System (SWIS) [12]. Fast protection operating times minimise danger, system instability and primary equipment damage. The fastest possible total fault clearance time which provides discrimination when required must therefore be set.

The main protection system shall satisfy all of the following conditions:

1) Achieve the relevant total fault clearance time specified by the Technical Rules and summarised in Section 2.6. Required operating times for the 1st and 2nd protection schemes listed in Section 2.6 may be interchanged.

2) Achieve critical fault clearance times where specified by the system analysis and solutions section

3) Achieve total fault clearance time to minimise thermal damage to primary equipment

Maximum total fault clearance times are given for main (no CB Fail) conditions and for backup (CB Fail) conditions. The total fault clearance time is illustrated in Figure 2.1 and Figure 2.2 below. Note that a standard safety margin of 10 milliseconds is applied.

[12] Technical Rules section 2.9.4

Figure 2.1 – Maximum total fault clearance time for main (no CB Fail) protection system

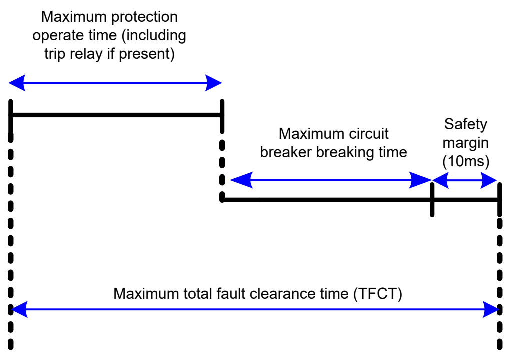
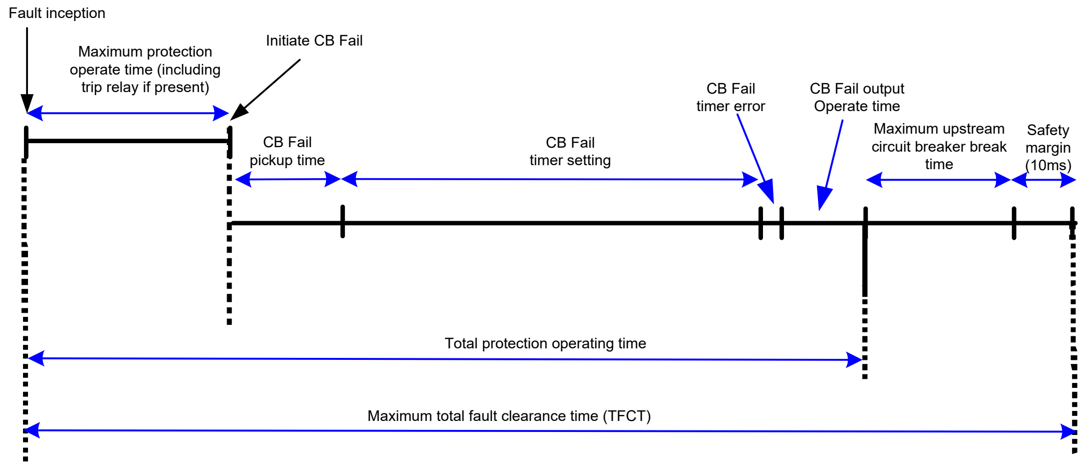


Figure 2.2 – Maximum total fault clearance time for backup (CB Fail) protection system



2.5.4.1 Determination of Relevant Total Fault Clearance Time

The relevant fault clearance time is determined by:

1) Transmission system. The location and voltage of the CB that isolates the fault determines the fault clearance time [13].
2) Distribution system. The location and the nominal voltage of the circuit that is faulted determines the fault clearance time [14].

2.5.4.2 Low Level Faults

The Technical Rules specify "zero impedance short circuit faults on primary equipment at nominal system voltage" [15] when defining operating times. This implies that low level faults do not need to meet any fault clearance time. Examples are transformer winding faults causing restricted earth fault, buchholz or winding temperature operation. Even though not required by the Technical Rules fast clearance is critical to minimising damage to critical infrastructure.

[13] Technical Rules clause 2.9.4(b) first sentence
[14] Technical Rules, clause 2.9.4(b), second sentence
[15] Technical Rules, clause 2.9.4(a)

2.5.4.3 Small Zone faults

CTs are only located on one side of a circuit breaker because of cost. This results in a blind-spot between the circuit breaker and the CT commonly called a 'small zone fault'. Faults supplied from a remote source will not be cleared by the local main protection system. Small zone faults shall be cleared by either local or remote backup protection systems.

Small zone faults shall be cleared as though it were a fault involving a circuit breaker failure [16]. This is considered acceptable because:

1) The physical extent of the small zone is limited.
2) Multi-phase faults (which could potentially result in system instability with the clearance times indicated) in a small zone are comparatively rare.
3) The cost of providing CTs on both sides of a circuit breaker is prohibitive.

Duplicate (backup) protection for small zone faults is required to cater for the situation where there is a small zone fault with CB Fail relay failure – this is reflected in the Technical Rules clause 2.9.2(a)(2).

A fault clearance time for a small zone fault coupled with a circuit breaker failure is not defined [17]. The only requirement is that this fault must be cleared by a protection system.

2.5.4.4 Backup Scheme Requirements for 66 kV Lines Greater than 40 km

The backup requirements for 66 kV lines greater than 40 km are not defined [18]. The CB Fail times outlined in Technical Rules Table 2.11 apply in this instance.

2.5.4.5 Existing versus New Equipment

Many existing protection systems do not meet the technical criteria outlined in the Technical Rules. The Technical Rules deem that all equipment installed prior to 1 July 2007 comply with the Technical Rules [19].

The Technical Rules indicate that different fault clearance times are applicable, depending on whether the installed equipment is "Existing" or "New" [20]. Existing equipment installed prior to 1 July 2007 is not required to meet the maximum total fault clearance times.

When replacing a component of the protection system the piece of replacement equipment must comply with the Technical Rules requirements for a complete asset replacement. An example is replacing a 132 kV CB operating in 80 ms with a 132 kV circuit breaker operating in 60 ms. Other equipment that existed at the Technical Rules commencement date does not have to meet this requirement [21].

It is unreasonable to upgrade an existing circuit to meet "Existing" times if only changing a component of the protection system (e.g. circuit breaker). To do so could be prohibitively expensive (e.g. adding a communications link between sites). An exception to this is replacement of line overcurrent protection with time stepped distance protection. This can be done at minimal incremental cost.

[16] Technical Rules, clause 2.9.4(d)
[17] Technical Rules, clause 2.9.4(e)
[18] Technical Rules, clause 2.9.4(d)(3)
[19] Technical Rules, clause 1.9.4(a)
[20] Technical Rules, Section 2.9.4, Table 11 and Table 12
[21] Technical Rules, clause 1.9.4(b)

If an existing protection system's total fault clearance time endangers the system or poses credible risks to the system (i.e. instability) then there is justification for upgrading the entire protection system. This decision is made by the asset manager.

The replacement of a piece of primary equipment which can impact fault levels must meet the fault clearance times specified for "New" Equipment. Examples are transformers or transmission lines.

2.5.4.6 Total Fault Clearance Time Requests

Stakeholders often ask the protection and automation section to provide total fault clearance times for protection systems on the SWIS. Typical uses for this information include earth potential rise calculations for earth grid designs, and system stability studies.

The objectives of performing these calculations are:

1) To provide clearance times that reflect both the current state and eventual future state of the network.
2) To ensure that all relevant clearance time requirements are considered, including Technical Rules times, and critical fault clearance times.

2.5.4.6.1 Recording of Critical Fault Clearance Times

A prerequisite for ensuring that the protection system meets critical fault clearance time requirements, is that an accurate, complete, and up-to-date database of said critical fault clearance times (CFCTs) must be maintained.

The TFCT spreadsheet will be used to record critical fault clearance time information for this purpose. This information is to be requested from GT. The process for requesting and recording CFCTs is documented within the TFCT spreadsheet.

2.5.4.6.2 Calculation of Actual TFCTs for the Transmission System

The process for calculating these times for the transmission system is as indicated below:

1) Calculate actual fault clearance times for Protection 1 and Protection 2 at each end of the line (including both remote end close and open).
    a) When requested, also calculate the actual fault clearance times for the HV bus zones and / or TX HV bushings.
    b) NOTE: Calculation of actual times should use stated component times and avoid rounding, unless stated component times are considered unrealistic and cannot be verified (e.g. CB breaking time is <30ms for 132kV).
2) Record the calculated actual times in the TFCT spreadsheet.

2.5.4.6.3 Calculation of Recommended Total Fault Clearance Times for the Transmission System

The total fault clearance time values provided to stakeholders will be a recommended time calculated based on a combination of:

1) Calculated actual total fault clearance times
2) Technical rules mandated total fault clearance times
3) Critical fault clearance time requirements

The process for calculating these recommended times is largely automated within the TFCT spreadsheet.

The formulae for calculating recommended times is outlined in the table below.

Table 2.3 – Process for Calculating Recommended TFCTs

Conditions	Recommended TFCT
Critical FCT < Tech Rules TFCT AND Actual TFCT > Critical FCT	Recommended TFCT = Actual TFCT (Important: GT must be notified if Actual TFCT > Critical FCT)
Critical FCT < Tech Rules TFCT AND Actual TFCT ≤ Critical FCT	Recommended TFCT = Critical FCT
Critical FCT ≥ Tech Rules TFCT AND Actual TFCT > Tech Rules TFCT	Recommended TFCT = Actual TFCT (Important: GT must be notified if Actual TFCT > Critical FCT)
Critical FCT ≥ Tech Rules TFCT AND Actual TFCT ≤ Tech Rules TFCT	Recommended TFCT = Tech Rules TFCT

Referring to the table above, the Technical Rules TFCT values shall be calculated as per the table below. This calculation is also automated within the TFCT spreadsheet.

Table 2.4 – Process for Calculating Technical Rules TFCTs

Scheme Type	Technical Rules TFCT
Unit Scheme e.g. digital diff, pilot	Local TFCT = Table 2.10 / New Equipment / Local End
	Remote TFCT = Table 2.10 / New Equipment / Local End
Non-Unit Scheme e.g .interlocked distance	Local TFCT = Table 2.10 / New Equipment / Local End
	Remote TFCT = Table 2.10 / New Equipment / Remote End

Note that both P1 and P2 will be compared with Technical Rules Table 2.10. This is in line with current practice, as we design new installations where both P1 and P2 should meet Table 2.10. Current practice for brownfields design should also result in both P1 and P2 moving towards meeting Technical Rules Table 2.10.

Please provide only recommended total fault clearance times to all stakeholders.

2.5.4.6.4 Calculation of Recommended TFCTs for the Distribution System

The process for providing these times for the distribution system is as indicated below:

1) Determine worst case earth fault setting that achieves a total fault clearance time of 1.16 sec for a feeder earth fault located at the substation under maximum system conditions. This normally involves calculating the time multiplier setting (TMS) for a pickup of 60 A.

2) Using existing settings, calculate the total fault clearance time for a feeder earth fault at the substation under maximum system conditions.

3) If the time calculated in (2) is greater than or equal to 1.16 seconds, use existing settings to calculate the total fault clearance time for a feeder earth fault at the location requested under maximum system conditions.

4) If time calculated in (2) is less than 1.16 seconds, use the worst case TMS determined in (1) and a 60 A pickup to calculate total fault clearance time at location requested for 50% of earth fault level under minimum system conditions

5) Use existing settings to calculate the total fault clearance time for a feeder earth fault at the location requested at 50% of the earth fault level under minimum system conditions.

6) Compare the time calculated in (5) with the time calculated in (4) and provide the greater of the two times.

7) Earth fault levels may be significant for solidly earthed transformers. Calculate the total fault clearance time by O/C protection that meets the I^2t time (applying A/R as appropriate to site) at max fault level. Provide this time if it is greater than actual time and less than the earth fault protection relay clearance time.

2.5.4.7 Non-Compliance

The maximum total fault clearance times specified by the Technical Rules must be met for all system conditions stronger than or equal to minimum system conditions. There are conditions where an application to derogate from the Technical Rules maximum total fault clearance time requirements may be reasonable. An example is a weak in-feed condition. In these cases the application for derogation would be supported by Western Power under the following conditions:

1) There is no threat to power system stability

2) There is no reduction in the power transfer limits

3) There is no possible plant damage (e.g. thermal)

4) There is no threat to the safety of public and staff

All estimates provided by Protection & Automation will provide a fully compliant Technical Rules solution. The Protection & Automation estimator will inform the estimating manager if estimator deems that a Technical Rules derogation could result in a significant cost saving. The estimating manager will inform the project sponsor who is then responsible for applying for the derogation.

2.5.5 Critical Fault Clearance Times

The critical fault clearance time (CFCT) is the slowest fault clearance time which permits the network to remain stable.

If a CFCT is present on a circuit both schemes of the protection system must operate within the nominated CFCT [22]. This requirement includes both the transmission and distribution systems. System stability relates to both rotor angle stability and voltage stability.

[22] Technical Rules section 2.9.5

2.5.5.1 Rotor Angle Stability

Under normal conditions generators operating with different outputs are kept synchronised by the common voltage between them (Figure 2.3).

A 3 phase fault will:

1) Short out load preventing power transfer

2) Remove the common voltage keeping the generators synchronised.

With the load and synchronising voltage removed the generators will accelerate according to their individual inertias and governor characteristics (Figure 2.4). The angle between the generator rotors will vary according to the generator's acceleration.

The individual generator speeds increase at different rates causing the rotor angles to diverge. The angles will continue to diverge after the fault is cleared as the generators will be running above 50 Hz and will take some time to slow down. After the difference in rotor angles reaches a critical angle, normally considered to be 180º, pole slip is considered to have occurred. If the fault is cleared before the critical angle is exceeded, the generators will return to synchronism (Figure 2.5). If the fault is not cleared before the critical angle is exceeded, the system will become unstable (Figure 2.6). The fault clearance time required to prevent the critical angle being exceeded is the critical fault clearance time.

Figure 2.3 – Pre fault generation

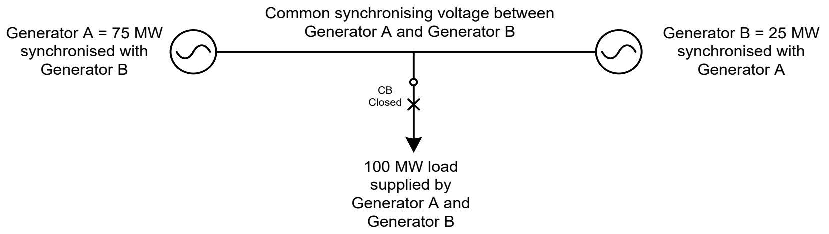


Figure 2.4 – Post fault generation immediately after fault inception

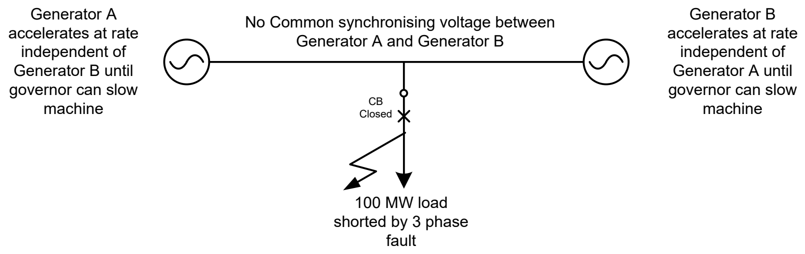


Figure 2.5 – Post fault generation if fault cleared within CFCT

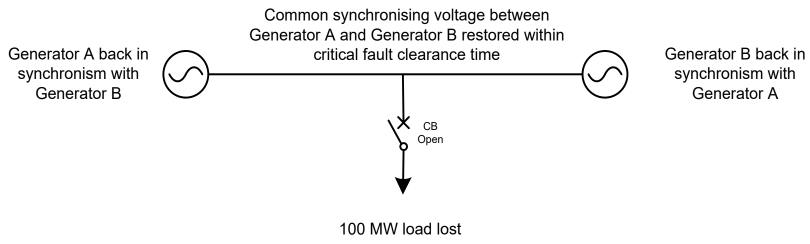
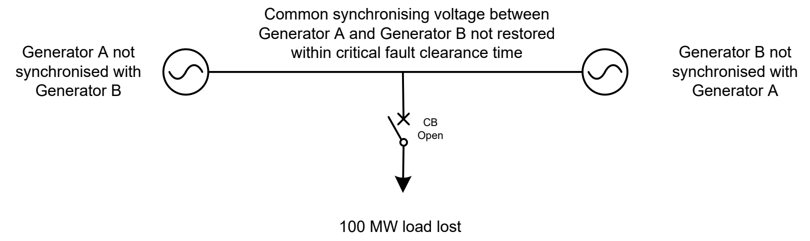


Figure 2.6 – Post fault generation if fault not cleared within CFCT



2.5.5.2 *Voltage Stability*

The voltage stability that is of main concern relates to the performance of induction motors on the network. During normal system conditions the reactive requirements of induction motors are supplied by static capacitor banks. A three phase fault depresses the voltage on the network and results in induction motors slowing down. When the fault is cleared the induction motors try to accelerate to their normal speed. During the acceleration the induction motors draw significantly more vars than during normal running. It is similar to the vars drawn during direct on line starting. The increase in the vars drawn by the motors reduces the voltage. The reduction in the voltage also reduces the amount of vars produced by capacitor banks. This can lead to a voltage collapse where the voltage does not recover to the normal operating range. Clearing the fault faster reduces the speed reduction of induction motors which in turn reduces the var requirement on acceleration.

2.5.6 Protection Sensitivity

All primary faults must be detected by a main and backup protection schemes under both normal and minimum system conditions.

Under abnormal equipment conditions involving 2 primary plant outages, all primary faults must be detected by one protection scheme and cleared by one protection system. Backup protection systems are acceptable.

Specific emergency conditions as defined by the transmission system planning section shall also be catered for. Protection operation under arbitrary emergency conditions is not guaranteed.

2.5.6.1 *Sensitivity Assessment*

Sensitivity assessment is based on:

1) The type of fault.

2) The worst case fault level in the protected zone. This is usually at the extreme of the protected zone.

3) Minimum system or abnormal equipment conditions. Minimum system conditions defines what protection systems are required, how they are implemented and how fast they must operate.

2.5.6.1.1 Minimum System Conditions

Minimum system conditions are the worst case and are used to determine the total fault clearance time of a protection scheme. Total fault clearance times must be met by all protection schemes for minimum system fault levels [23]. To determine the appropriate minimum fault level, the following conditions must be applied [24]:

1) The least number of generating units normally connected at times of minimum generation are so connected; and

2) There is one primary equipment outage.

Most relay operation times are quoted at a minimum of twice the pickup. A factor of 50% must therefore be applied. Refer to Section 16 – Protection Sensitivity for more information.

2.5.6.1.2 Abnormal Equipment Conditions

All primary faults must be detected by a protection scheme somewhere in the system under abnormal equipment conditions. Remote backup protection may be used in situations involving two primary equipment outages [25].

The Technical Rules do not require both a main and backup protection to operate so it is implied the circuit breaker failure does not have to be catered for.

2.5.6.1.2.1 Involving Two Primary Plant Outages

Requirements for discrimination, sensitivity and fault clearance time are not defined in the Technical Rules [26].

Abnormal equipment conditions involving two primary plant outages define how sensitive one of the main protection schemes should be.

The following characterise an abnormal equipment condition with two primary plant outages:

1) Remote backup may be used. Remote schemes that can be used are:

    a) Remote IDMT earth fault protection relays which are effective for earth faults only

    b) Remote zone 4 reaches

2) Discrimination is not required

3) Fault clearance times are not specified under these conditions

At least one main protection scheme must be designed and set to ensure all faults are detected under this condition.

[23] Technical Rules, section 2.9.6 (b)
[24] Technical Rules, Attachment 1 – Glossary, definition of minimum system condition
[25] Technical Rules section 2.9.6(c)
[26] Technical Rules section 2.9.6(c)

2.5.6.1.2.2 Not Involving Two Primary Plant Outages

Requirements for discrimination, sensitivity and fault clearance time are not defined in the Technical Rules. Abnormal conditions not involving two primary plant outages defines how sensitive both protection systems must be.

Abnormal equipment conditions not involving two primary plant outages define how sensitive both main protection schemes should be.

The Technical Rules do not define fault clearance times or discrimination requirements for abnormal equipment conditions not involving two primary equipment outages. And example of this condition includes:

1) Minimum system conditions
2) Plus one worst case generating unit outage
3) Plus one primary equipment outage
4) Plus one secondary equipment outage

It is reasonable that both main protection schemes should be able to operate and discriminate for faults in their intended operating zone under this condition. It is also considered reasonable that these protection systems are not required to meet specified total fault clearance times.

2.6 Appendix A – Maximum Total Fault Clearance Times [27]

Total fault clearance times are specified at the voltage level of the circuit breaker clearing the fault, not the voltage level of the fault location.

The clearance type (local or remote) depends on the fault location in relation to the circuit breaker clearing the fault.

Times shown are from Table 2.11 and 2.12 of the Technical Rules and reflect minimum requirements. Site specific requirements may require faster times.

2.6.1 Existing Equipment

Voltage	Line Length	Protection Scheme	Clearance Type	Main Protection System (msec) No CB Fail	Backup Protection System (msec) CB Fail
≥ 220 kV	All	Protection 1	Local	120	370
			Remote	180	420
		Protection 2	Local	120	370
			Remote	180	420
132 kV	≤ 40 km	Protection 1	Local	150	400
			Remote	200	450
		Protection 2	Local	150	400
			Remote	400	400
	> 40 km	Protection 1	Local	150	400
			Remote	400	650
		Protection 2	Local	150	400
			Remote	400	650
66 kV	≤ 40 km	Protection 1	Local	150	400
			Remote	200	450
		Protection 2	Local	1000	400
			Remote	Not Defined	400
	> 40 km	Protection 1	Local	150	400
			Remote	400	650
		Protection 2	Local	1000	Not Defined
			Remote	Not Defined	Not Defined
≤ 33 kV	N/A	Protection 1	Local	1160	1500

[27] Technical Rules section 2.9.4

2.6.2 New Equipment

Voltage	Line Length	Protection Scheme	Clearance Type	Main Protection System (msec) No CB Fail	Backup Protection System (msec) CB Fail
≥ 220 kV	All	Protection 1	Local	100	270
			Remote	140	315
		Protection 2	Local	100	270
			Remote	140	315
132 kV	≤ 40 km	Protection 1	Local	115	310
			Remote	160	355
		Protection 2	Local	115	310
			Remote	400	400
	> 40 km	Protection 1	Local	115	310
			Remote	400	565
		Protection 2	Local	115	310
			Remote	400	565
66 kV	≤ 40 km	Protection 1	Local	115	310
			Remote	160	355
		Protection 2	Local	115	310
			Remote	400	400
	> 40 km	Protection 1	Local	115	310
			Remote	400	565
		Protection 2	Local	115	310
			Remote	400	565
≤ 33 kV	N/A	Protection 1	Local	1160	1500

The Technical Rules do not specifically state that the backup times from Table 2.11 are acceptable for 66 kV lines longer than 40 km. Because these times are acceptable for 132 kV, it is implied that they are acceptable for 66 kV as well.

2.7 Appendix B – Summary of Technical Rules Requirements for Discrimination, Sensitivity and Maximum Total Fault Clearance Times

System Conditions		Discrimination		Sensitivity	Clearance Times
Description	Total Plant Outages	Minimum FL	Maximum FL	Minimum FL	
Maximum system	None	Met by P1 & P2	Met by P1 & P2	Met by P1 & P2	Met by P1 & P2
Minimum System [28]	Minimum generation and 1 primary equipment outage	Met by P1 & P2	Met by P1 & P2	Met by P1 & P2	Met by P1 & P2
Abnormal System (a) [29]	Minimum generation and 1 worst case generating unit outage and 1 primary equipment outage and 1 secondary equipment outage	Met by P1 & P2	Met by P1 & P2	Met by P1 & P2	Not defined
Abnormal System (b) [30]	Minimum generation and 1 worst case generating unit outage and 2 primary equipment outages	Not Required	Not Required	Met by a protection scheme (main is desirable, but backup is acceptable)	Not defined
Emergency	Not Defined but worse than any above	Not Required	Not Required	May be met by an adjacent protection scheme	Not defined

Each system in column 1 is modelled in PSSE or Power Factory by removing the items shown in column 2. PSSE or Power Factory is used to determine the maximum or minimum fault levels corresponding to the outages specified in column 2.

2.7.1 Minimum Fault Levels

Checking sensitivity of the protection system under normal conditions involves:

1) Use the PSSE or Power Factory minimum generation case. The PSSE minimum generation case already contains generator and circuit outages typical of the present day minimum generation pattern.

2) Remove the circuit with the largest fault contribution

2.7.2 Maximum Fault Levels

Maximum fault levels can increase due to additional generation being added to the system. The protection performance must be examined in the following order of preference:

1) An infinite bus allows for future generation and is therefore preferred.

[28] Minimum system conditions defines what protection systems are required, how they are implemented and how fast they must operate

[29] Requirements for discrimination, sensitivity and fault clearance time are not defined in the Technical Rules. Used for system backup protection. This defines how sensitive both protection systems must be

[30] Requirements for discrimination, sensitivity and fault clearance time are not defined in the Technical Rules. Used for system backup protection. This defines how sensitive at least 1 protection system must be

2) If acceptable protection performance cannot be achieved with preference 1 then switchgear fault rating is used

3) If acceptable protection performance cannot be achieved with preferences 1 & 2, the maximum present day fault levels plus a margin is used. When this preference is used, limitations must be documented.

3 Transmission Line and Cable Protection

3.1 Introduction

The purposes of this section are to:

1) Define at a high level the high level functional requirements for transmission line and cable protection
2) Capture information which explains the reasoning behind the transmission line and cable protection design and settings

3.2 Scope

This section applies to line and cable circuits within the Western Power transmission system. Distribution overhead line and underground cable protection are not covered in this section.

3.3 Functional Requirements

The functional requirements for the transmission line protection systems are:

1) Detect and clear faults in the transmission line operating zone. Refer to Section 3.7 – Appendix C – Transmission Line and Cable Operating Zones.
2) Detect and clear faults within times specified by the Technical Rules.
3) Coordinate with upstream and downstream protection systems.
4) Provide system backup protection
5) Clear faults within the thermal limits of associated primary equipment, including the power transformer.
6) It is not a purpose of the transmission line protection systems to provide overload, over voltage or under voltage protection for circuit breakers, transformers or conductors.

3.4 Transmission Line and Cable Protection

3.4.1 Introduction

The main purpose of the transmission line protection system is to minimise danger to the staff and public and minimise loss of supply by clearing faults on the transmission line. Other purposes include control and monitoring to facilitate operation of the transmission line, transmit signals between sites and to minimise damage to primary equipment.

The transmission line protection system must take into account the following system considerations:

1) Line length
2) Line conductor used
3) Line arrangement, such as teed line or transformer feeder
4) Equipment connected to the line, such as shunt reactors or series capacitors
5) Maximum and minimum fault currents

6) Line load and charging currents

7) Relative importance of the protected line

8) System performance demands such as stability, power swings, and critical fault clearance times.

9) Availability of communications bearers and signalling channels

3.4.1.1 Differential Protection

The detection of faults by detecting differential currents is widely used for protection of many types of primary equipment including transmission lines. Differential protection is based on the principle that the current entering a non-faulted object equals the current leaving the object.

Current transformers (CT) are located at each end of the transmission line. The current transformers define the operating zone. A fault within the operating zone will make the current entering the operating zone higher than the current leaving. The difference in currents is called the differential current. Protection relays detect the differential current and issue trip commands to both ends of the line.

A transmission line protection operation will result in the tripping of a single circuit which should not result in loss of load under normal conditions. For this reason priority is given to the sensitivity of the scheme. In general, the minimum possible relay setting, which still provides adequate margin for charging current and load, is chosen to provide this sensitivity.

3.4.1.1.1 Digital Differential Protection

The protection relays at each end of the line measures and samples the secondary current waveform. This information is digitally transmitted to the relay at the other end via a communications channel. The protection relays at each end then calculate if the proportion of differential current to restraint current is within an operating characteristic. If so, the relay issues a trip command.

3.4.1.1.1.1 Stub Protection

Bus stubs are found in multi circuit breaker configurations such as 1.5 circuit breaker, double bus and mesh terminal stations. A stub is formed when:

1) A line disconnector is opened to isolate a line and

2) The circuit breakers are closed to maintain bus continuity

Stub protection uses the line disconnector status to disable inter-tripping and transfer of current measurement information from the local relay to the remote relay. Under these conditions instantaneous overcurrent usually provides stub protection. This allows the line to remain energised from the remote end for a fault on the stub.

When stub protection is not enabled the differential line protection trips at both ends for a fault on the stub.

Western Power considers that the disadvantages of enabling stub protection outweigh the minor operational advantages. Western Power, therefore, does not implement stub protection in differential protection schemes. Refer to section 3.8.3.

3.4.1.1.2 Pilot Protection

Three phase line currents at each end are converted into a low level, single phase quantity by a summation transformer. These low level signals are fed into the pilot wire and compared at each end.

The pilot protection relays typically have an insulation rating of 5 kV. Isolation transformers are rated for 15 kV and allow the pilot wires to be strung below the 22 kV (12.7 kV L-E) or less distribution feeders. If a feeder conductor falls on a pilot wire the isolation transformers prevent the distribution voltage being transferred to the protection panel.

A pilot cable route between two substations is not always direct and may go between intermediate substations. Isolation transformers are used at the intermediate substations to prevent large voltages entering the intermediate substation through the pilot cable. When used at intermediate substations these isolation transformers are called sectionalizing isolating transformers.

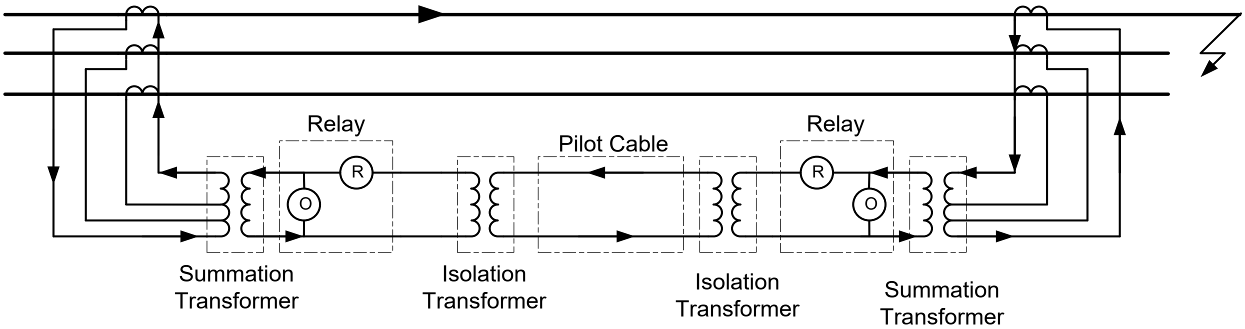
3.4.1.1.2.1 Circulating Current

For through faults, secondary currents circulating between the CTs at the line ends flow through the restraint element of the pilot relays. The operate elements are not energised. For in-zone faults, differential current flows through the operate elements of the pilot relays.

An open circuit pilot cable will result in current flowing through the operate elements of the pilot relays causing both ends to trip.

The scheme will remain stable for a short circuit in the pilot cable.

Figure 3.1 – Circulating current pilot scheme



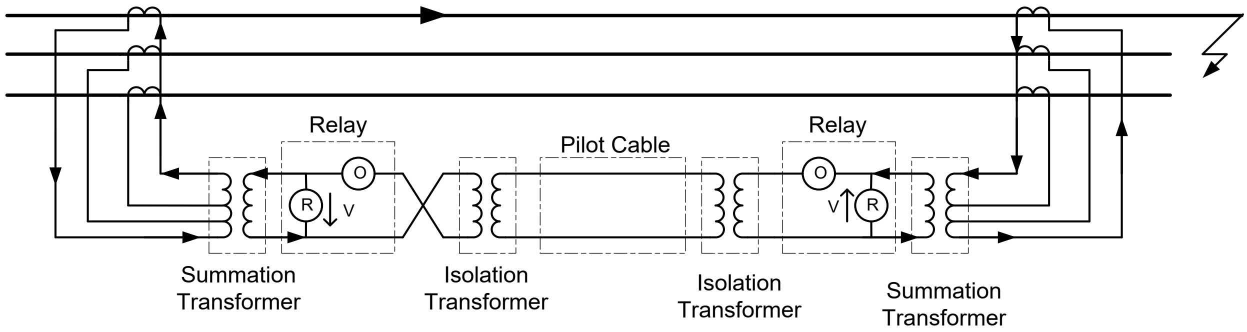
3.4.1.1.2.2 Opposed Voltages

For through faults, secondary voltages from each of the two line ends are equal and opposite. When put across a relay operate element, no current flows and the scheme is stable. For in-zone faults, the voltages are unequal which causes differential current to flow through the operate elements of the pilot relays.

A short circuit in the pilot cable will result in a voltage across the operate elements in the pilot relays causing both ends to trip. Short circuiting the pilot scheme at one end of the line can be used to send an inter-trip to the other end.

The scheme will remain stable for an open circuit in the pilot cable.

Figure 3.2 – Opposed voltage pilot scheme



3.4.1.2 Distance Protection

The detection of faults using the principle of fault impedance is commonly called distance protection. At the time of a fault, the voltage and current measurements allow the protection relay to calculate the impedance to the fault. By comparing this value to the known line impedance, the protection relay determines if the fault is on the line. When the protection relay determines that the fault impedance is less than the line impedance, it issues a trip command.

3.4.1.2.1 Time Stepped Distance Protection

A fault at the local end of a line may appear to be at the remote end of another line due to primary equipment, calculation or relay inaccuracies.

1) To cater for these errors and increase system reliability a time stepped Trip instantly for faults which are definitely on the line. This operating zone is referred to zone 1. The zone 1 reach generally extends to 80% of the protected line impedance

2) Trip after a delay for faults beyond the zone 1 reach. This operating zone is referred to as zone 2 and allows adjacent line protection systems to operate first.

Time stepped distance protection schemes are not required to interface with the protection schemes at the other end of the line circuit. They therefore do not require communications and are considered non-unit protection schemes.

3.4.1.2.2 Interlocked Distance Schemes

Use of signalling channels between distance relays improves operating time, sensitivity and reliability.

Interlocked distance schemes are used to:

1) Quickly clear faults on transmission lines. To meet critical fault clearance times distance protection is interlocked on main protection schemes for voltages of 220 kV and above.

2) Improve sensitivity. On short lines, time stepped distance protection may not provide adequate fault sensitivity.

Section 3.8.2 summarises advantages and disadvantages of the permissive and block signalling protection schemes.

3.4.1.2.2.1 Direct Inter-tripping

When a local relay detects a fault in zone 1, it trips and also sends an inter-trip to the remote end. A disadvantage of direct inter-tripping is that it relies heavily on the communications for security.

Because the signal is not conditioned at the receiving end, the receiving end will trip if the communications system sends an incorrect signal.

If a line is open at one end and a fault occurs at the open end, the fault will be cleared in the non-unit time (zone 2).

For these reasons, direct inter-tripping shall not be used for new protection schemes.

3.4.1.2.2.2 Permissive Signalling

Permissive signalling involves sending and receipt of a permissive signal that enables tripping. The permissive signal is conditioned by an over reaching element at the receiving end. If a relay's over reaching element is picked up and it receives a permissive signal, the relay will issue a trip.

There are two types of permissive signalling:

1) Permissive over reach (POR). A local over reaching element (zone 2) is used to send the permissive signal to the remote end.

2) Permissive under reach (PUR). A local under reaching element (zone 1) is used to send the permissive signal to the remote end.

3.4.1.2.2.3 Block Signalling

Block signalling involves sending and receiving a block signal that prevents tripping. If a Zone 3 reverse direction element picks up, a block signal is sent to the remote end. If an over or under reaching element picks up, the block signal is not sent to the remote end. The block signal is conditioned by an over reaching element at the receiving end. If the remote end over reaching element is picked up and the block signal is not present after a defined time delay, the relay will issue a trip.

There are two types of block signalling:

1) Block over reach (BOR). A local over reaching element (zone 2) is used to prevent the block signal from being sent to the remote end.

2) Block under reach (BUR). A local under reaching element (zone 1) is used to prevent the block signal from being sent to the remote end.

3.4.1.2.2.4 Unblocking

Unblocking is preferred when power line carrier (PLC) communications is used.

Unblocking schemes are similar in principle to permissive over-reach schemes. The local unblocking relay receives a continuous blocking signal from the remote end. When remote over-reaching distance elements operate, the frequency of the signal is converted to an unblocking, or trip, signal.

Unblocking schemes are more reliable than POR schemes. Loss of both the block and unblock signal from the remote end is detected by the local unblock relay. Loss of these signals allows local tripping for a period typically 100 to 150 milliseconds if a local distance element picks up. After this period, an unblock signal is again required for tripping.

Unblocking schemes are more secure than blocking schemes because tripping for an external fault is only possible during the 100 to 150 millisecond signal failure interval.

3.4.2 Design Requirements

Standard functions are provided on all transmission line circuits to assist with standardisation of protection design and setting files. Site specific functions are provided at the discretion of the protection design engineer.

Section 3.5 outlines the design requirements for standard functions and site specific functions.

3.4.2.1 Main Protection System

The operating zone of the main protection system is defined by the current transformers at each end of the transmission line. Each main protection scheme must be able to protect the line with the other main protection scheme out of service.

At voltages of 220 kV and above, both main protections schemes must be differential or interlocked distance schemes to meet required total fault clearance time. Below 220 kV, both main protection schemes may be required to be differential or interlocked distance schemes to achieve critical fault clearance times or ensure discrimination.

3.4.2.1.1 Main Protection System Components

When cutting into an existing line protection system, the new protection system must:

1) Be selected to minimise the change to existing hardware and protection schemes at the remote ends, and

2) Meet the Technical Rules requirements

As the availability of digital communications is increasing it is becoming less costly to upgrade protection schemes from analogue to digital. This allows faster clearance times.

3.4.2.1.2 Main Protection System Selection

The selection of the protection system depends on:

1) Fault clearance time requirements
2) Line configuration (i.e. two or three ended)
3) Auto reclose requirements
4) Weak infeed
5) Communications availability

Section 3.9 summarises the main protection system selection criteria.

3.4.2.2 Point on Wave Switching

Lines connected to the transmission system can have an excessive voltage step when switched. A large voltage step results in excessive circuit breaker contact wear. Point on wave switching of independent circuit breaker poles reduces this voltage step. The requirement for point on wave switching is determined by system analysis and solutions and the transmission plant sections.

3.4.2.3 Duplicated Protection

To help maintain consistency throughout the system, main protection system 1 has been chosen for the unit protection. This should be adhered to except when matching existing installations. The relays should be the same or as similar as possible when matching existing installations.

Interlocked distance is acceptable for both main protection schemes when critical fault clearance times (CFCT) require high speed clearance of faults. Both protections schemes must meet the CFCT requirement if the CFCT requirement is less than the Technical Rules total fault clearance time requirement.

Directional earth fault protection will be used on all lines, preferably as part of main protection system 2. Directional earth fault protection detects high resistance earth faults. It also provides system back up protection.

3.4.2.4 Current Differential

Current differential protection must include supervision facilities to alarm and block tripping for loss of communications. Supervision reduces the security risk to the major transmission system for a failed communications bearer.

3.4.2.5 Pilot Protection

Circulating current or opposed voltage pilot schemes shall not be used for new circuits. Circulating current protection over metallic pilots must utilise pilot supervision that both alarms and blocks tripping on detecting cable damage. The method used to block tripping must not reduce sensitivity in normal operation. Supervision reduces the security risk to the major transmission system for a damaged pilot cable.

3.4.2.6 Distance Protection

Distance protection shall be used with all main protection schemes as either:

1) A main protection scheme

2) A backup protection scheme

3) A system backup protection scheme

Voltage supervision must be used in conjunction with all distance relays. The voltage transformer must be connected to the line it is protecting.

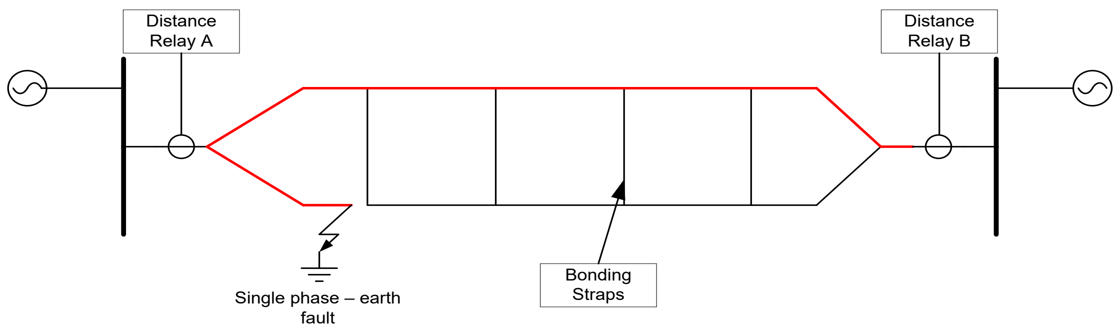
3.4.2.6.1 Split Phase Construction

The distance relay must be able to detect all faults on a line (including in-feed from the local end). Split phase construction of transmission lines often requires straps to be bonded across the split phases. This is to allow the zone 2 reach of the protection relays to detect faults should a conductor break and fall to the ground. Figure 3.3 below demonstrates that without bonding straps, distance relay B must be able to detect faults at up to twice the line length. This may exceed the maximum upper limit of the zone 2 reach. Figure 3.4 below demonstrates that bonding straps shorten the required relay B zone 2 reach.

The protection design engineer is responsible for determining the number and location of the bonding straps.

Figure 3.3 – Split phase construction with no bonding straps

Figure 3.4 – Split phase construction with bonding straps



3.4.2.6.2 Mutual Coupling

A mutual impedance exists between two line which are run in close proximity (e.g. on the same tower). This mutual impedance may allow current flowing in one circuit to induce a proportional voltage in the other circuit.

Due to symmetry, mutual coupling for faults clear of earth (i.e. positive and negative sequence currents only) has an affect of less than 5% and can therefore be neglected.

Zero sequence currents in a non-faulted line can induce a significant zero sequence voltage in the faulted line. This causes the impedance measured in the distance relay for earth faults to be incorrect. The apparent impedance can be less than or greater than the expected impedance, depending on the direction of the zero sequence currents in the two lines.

1) When the currents in the two parallel lines flow in opposite direction the measured voltage (and thus the apparent impedance) decreases. The relay therefore over-reaches.

   An earth fault beyond the desired zone 1 reach will cause the zone 1 element to assert and over-reach. Modern relays have a $K0_1$ setting to compensate for the mutual coupling. $K0_1$ is used to adjust the apparent impedance detected by the relay to be equal to the zone 1 reach.

2) When the currents in the two lines flow in the same direction the measured voltage and thus the apparent impedance increases. The relay therefore under-reaches.

   An earth fault at the remote end of the end of the line will cause the zone 2 element to under-reach. Modern relays have a $K0_2$ setting to compensate for the mutual coupling. $K0_2$ is used to adjust the apparent impedance detected by the relay to be equal to the zone 2 reach.

3.4.2.6.3 In-feed

Multiple in-feeds into a fault increase the apparent impedance detected by the relay [31].

If a distance reach is being used for remote backup, the apparent impedance must be calculated using the maximum in-feed possible. The minimum in-feed must also be used to calculate the apparent impedance to ensure discrimination.

The 20% margin in the minimum zone 2 setting allows for no in-feed to ensure discrimination.

3.4.2.6.4 Long Line Followed by a Short Line

A long line followed by a short line can result in loss of discrimination with time stepped distance schemes. If $Z_{\text{short line}} < 0.625\ Z_{\text{Long line}}$ it is not possible to satisfy the upper and lower limit requirements of zone 2 [32]. Not meeting this requirement results in the zone 2 timers of the long and short lines racing. If the long line zone 2 times out first, discrimination is lost.

Installing high speed protection on the short line will result in the short line zone 1 clearing a fault on the short line before the zone 2 time delay. Duplicated digital differential or interlocked protection schemes are therefore required on the short line.

3.4.2.6.5 Operating Characteristics

The following issues determine the type of operating characteristic to use:

1) Matching existing relays at remote ends

2) Load encroachment

3) Length of line to be protected

4) Required operating times

[33] Distance Relays Applications and Operating Principles, page 40.

[33] Distance Relays Applications and Operating Principles, page 40.

3.4.2.6.5.1 Mho Characteristic

When quadrilateral characteristics were introduced with electromechanical relays they were considered unstable. Mho characteristics have therefore historically been used for zone 1.

Zone 4 is usually configured as a Mho characteristic.

The maximum resistive reach of a mho characteristic is given by:

$$\mathrm{Zone}_{\mathrm{MaximumResistiveReach}} = \frac{\mathrm{ZoneReach}}{2} \times (1 + \cos\theta)$$

`where θ is the line angle

With a quadrilateral characteristic the R/X ratio is limited to 2/1. This is so the resistive reach of the equivalent Mho circle is not over reached.

3.4.2.6.5.2 Quadrilaterals

With the introduction of numerical relays quadrilateral characteristics have been considered stable. Quadrilateral characteristics are used for the zone 1 and 2 reaches. They are also sometimes used for the zone 3 reverse reach when used for backup or busbar protection. When used in an interlocked scheme where the remote zone 2 uses a quadrilateral characteristic, the local zone 3 must also use a quadrilateral characteristic.

With a quadrilateral characteristic the R/X ratio is limited to 2/1. This is so the resistive reach of the equivalent Mho circle is not over reached.

3.4.2.6.6 Power Swings

During system disturbances the relative rotor angle of machines in the system can move. This is as a result of some machines accelerating or decelerating depending upon their location relative to the fault. The impedance locus on a line between two groups of machines will display a characteristic power swing. The power swing can cause the apparent impedance presented to a distance relay to move from the load area to the relay operating characteristic. Because power swings move slowly compared to faults, it is possible to detect them and block the distance protection [33].

Power swing blocking allows the system time to return to a stable condition should a power swing occur. Power swing blocking is also known as out of step blocking. The requirement for power swing blocking is determined by the system analysis and solutions section.

3.4.2.6.7 Time Stepped Distance

Time stepped distance (TSD) protection must be included with current differential protection when possible. TSD provides system backup protection for primary equipment beyond the operating zone of the differential protection.

3.4.2.6.8 Interlocked Distance

At voltages less than 220 kV and depending on critical fault clearance times, interlocked distance schemes may not be required. However, when communications infrastructure exists, interlocked distance is preferred over time stepped distance.

[33] Distance Relays Applications and Operating Principles, page 40.

3.4.2.7 Communications

3.4.2.7.1 Unit Schemes

Unit protection schemes require end to end communications for their basic operating characteristic. Where duplicate unit schemes are used they must use separate independent communications bearers.

The types of bearers commonly used are microwave radio, fibre optic cable and metallic pilot cable. Less common is power line carrier because they require installation of capacitive voltage transformers (CVT) and wave traps.

Existing analogue communications systems may require upgrading to digital communications systems to meet total fault clearance time or critical fault clearance time (CFCT) requirements. Digital transmission times are on the order of 12 milliseconds. Analogue transmission times are on the order of 23 milliseconds.

3.4.3 Main Protection Systems Standard Functions

The following functions are standard for transmission line applications.

3.4.3.1 Differential

The purpose of differential protection is to detect and clear fault conditions resulting in differential currents.

The pickup settings are selected to meet the following requirements:

1) Lower limit:

   According to relay manufacturer recommendations.

2) Upper Limit:

   Meet Western Power's sensitivity requirements.

The sensitivity requirement takes precedence if these two requirements conflict.

3.4.3.2 Distance

All maximum zone reaches must be based on the maximum winter rating of the line plus a margin.

Distance protection may be included in the main protection system as system backup (i.e. in addition to the differential function). In this case discrimination is given a higher priority than sensitivity and total fault clearance time requirements. Note that the Technical Rules required backup systems must still meet the Technical Rules requirements for total fault clearance times and Western Power sensitivity requirements.

3.4.3.2.1 Zone 1

3.4.3.2.1.1 General

Zone 1 is fundamental to protecting the line circuit. The purpose of zone 1 is to detect most faults on the protected line.

Zone 1 is set in the forward direction.

Zone 1 is active at all times.

3.4.3.2.1.2 Zone 1 reach

1) Lower limit

Even with under-reach the relay must detect faults on at least 50% of the line.

2) Upper limit

For each end, a zone 1 reach will be set which provides as much coverage of the protected line as possible.

Even with out-feed on teed lines and with worst case relay errors this reach shall not extend beyond any end of the line.

When mutual coupling is present the $K0_1$ factor must prevent zone 1 from over-reaching.

It must not be possible for worst case load to encroach into the operating characteristic

a) Standard Settings

In the absence of mutual coupling the zone 1 reach of a two ended line is determined using the following method:

i) Numerical relays

Zone 1 reach = 0.85 x $Z_{Protected\_line}$

ii) Electromechanical relays

Zone 1 reach ≤ 0.85 x $Z_{Protected\_line}$

The plug setting resolution of the electromechanical relays forces the inequality. This inequality will still result in a reach of at least 80% of the protected line.

3.4.3.2.1.3 Time delay

Zone 1 shall not be intentionally time delayed.

3.4.3.2.2 Zone 2

3.4.3.2.2.1 General

Zone 2 ensures that all faults on the protected line are detected. Zone 2 also provides some remote backup for faults on adjacent lines, should their circuit breakers fail to operate.

Zone 2 is set in the forward direction.

Zone 2 is active at all times for 2 ended lines.

Zone 2 is only active when the differential protection is out of service on teed lines. Opening one end of a teed line will remove some in-feed. This may allow zone 2 to overreach adjacent circuits more than has been allowed for. Loss of discrimination may occur if the differential protection has failed.

3.4.3.2.2.2 Zone 2 Reach

When selecting an appropriate zone 2 reach setting, consideration must be given to the ability of the protection to operate for high impedance earth faults. Preference is therefore given to the upper limit setting.

1) Lower limit:

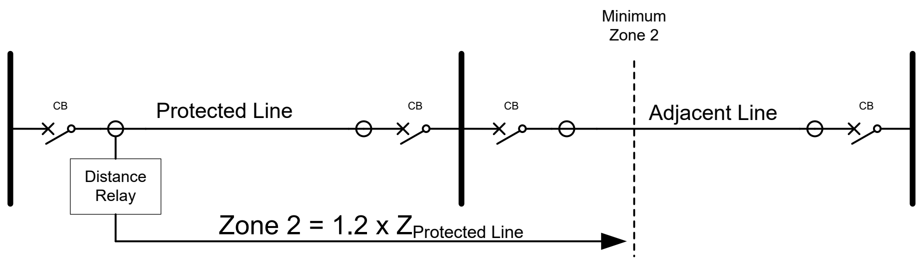
When mutual coupling is present the $K0_2$ factor must prevent zone 2 from under-reaching.

The lower limit of zone 2 is 120% of the protected line

a) Standard Setting

Zone 2 reach = 1.2 x $Z_{\text{Protected Line}}$

Figure 3.5 – Minimum zone 2 reach



2) Upper limit:

With split phase construction, the zone 2 reach must be able to detect an open circuit to ground fault on both phase conductors.

It must not be possible for worst case load to encroach into the operating characteristic

a) Standard Settings

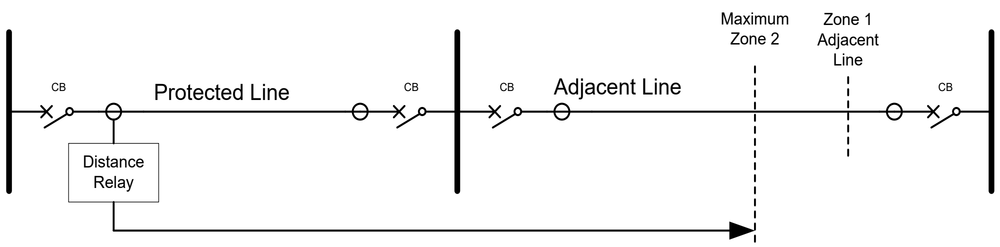
i) Maximum setting

Zone 2 should be set as large as possible to provide as much system backup and resistive reach for earth faults as possible.

It must not be possible for worst case load to encroach into the operating characteristic

Zone 2 reach = 0.8 x ($Z_{\text{Protected Line}}$ + Zone 1 reach $_{\text{Adjacent Line}}$)

Figure 3.6 – Maximum zone 2 reach

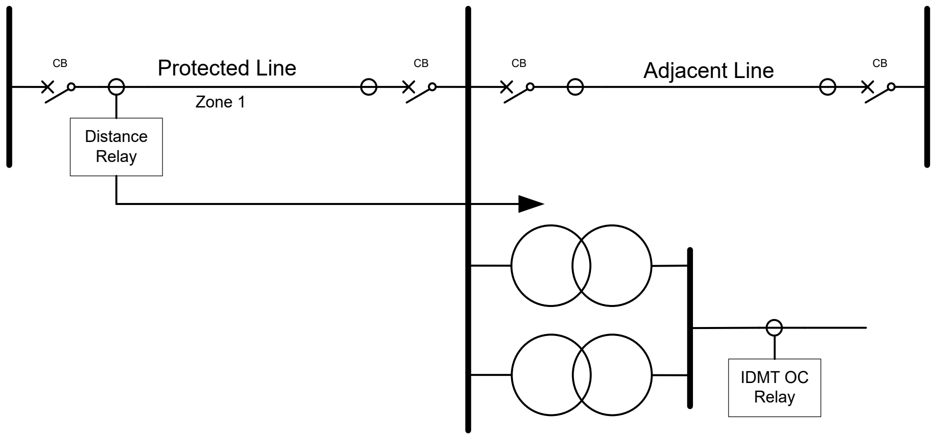


Zone 2 must not detect faults downstream from remote transformers whose windings supply systems protected by IDMT overcurrent protection schemes. (i.e. the zone 2 may operate faster than the IDMT overcurrent for an LV fault). The wost case is the lowest impedance combination of two parallel transformers. Under these conditions the maximum reach is:

Zone 2 reach ≤ 0.8 x [$Z_{\text{Protected Line}}$ + $Z_{\text{//\_Transformers}}$]

where $Z_{\text{//\_Transformers}}$ is the lowest possible parallel combination of transformers at the remote end that connect to a system protected by IDMT overcurrent relays.

Figure 3.7 – Zone 2 setting consideration



3.4.3.2.2.3 Zone 2 time delay

Zone 2 of the protected line must be delayed long enough to allow the adjacent line protection systems to clear faults on the adjacent line. The zone 2 delay must take into account the adjacent line's total fault clearance time.

When there are less than 2 CB Fail inter-trips between substations, zone 2 is required to ensure clearance of remote faults within 400 milliseconds.

1) Standard Setting

   a) When a Mho zone 2 characteristic is used, a zone 2 time delay of 300 milliseconds is typically used. This allows the zone 2 of the protected line to discriminate with the zone 1 of the adjacent line.

   b) When a quadrilateral zone 2 characteristic is used, a zone 2 delay of 2.5 seconds has been adopted as a standard. This allows the quadrilateral zone 2 characteristic of the protected line to discriminate with the earth fault and directional earth fault protection systems on adjacent lines.

3.4.3.2.3 Zone 3

3.4.3.2.3.1 General

Zone 3 can be used to:

1) Detect faults beyond the zone 1 of adjacent lines

2) Provide information for the operating logic of communications aided tripping schemes.

3) Provide system backup protection for faults in the reverse direction

4) Provide a de facto busbar protection. In such cases, the reverse reach is limited and operating times are faster.

5) Provide reverse protection for switch on to fault (SOTF) protection

6) Used to provide a backup protection scheme in 1.5 circuit breaker terminal stations when there is only relay providing CB Fail.

Zone 3 is set in the reverse direction.

Zone 3 is active at all time when used for tripping.

Zone 3 is configured to exceed the remote Zone 2 characteristic in communications aided schemes.

3.4.3.2.3.2 Zone 3 reach

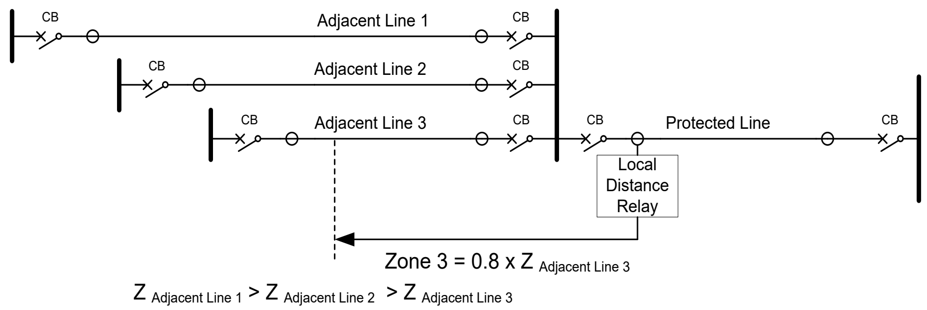
1) When used for switch on to fault or busbar protection:

   Zone 3 reach = detect faults on the busbar only (typically set to 10% of Zone 1)

2) When used for backup protection it must not be possible for worst case load to encroach into the operating characteristic:

   Zone 3 reach ≤ 0.8 $Z_{\text{LOWEST Impedance Line Behind The Relay}}$

Figure 3.8 – Zone 3 backup Reach

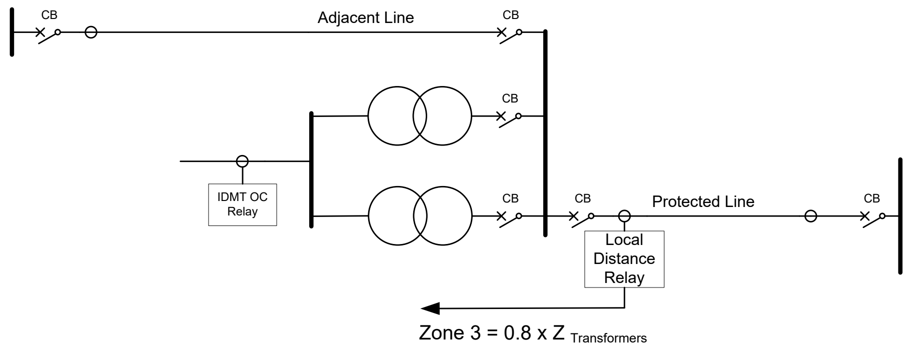


Zone 3 must not detect faults downstream from remote transformers whose windings supply systems protected by IDMT overcurrent protection schemes. (i.e. the zone 3 may operate faster than the IDMT overcurrent for an LV fault). The wost case is the lowest impedance combination of two parallel transformers. Under these conditions the maximum reach is:

Zone 3 reach ≤ 0.8 x [$Z_{\text{Protected Line}}$ + $Z_{\text{//\_Transformers}}$]

where $Z_{\text{//\_Transformers}}$ is the lowest possible parallel combination of transformers at the remote end that connect to a system protected by IDMT overcurrent relays.

Figure 3.9 – Zone 3 backup reach setting consideration



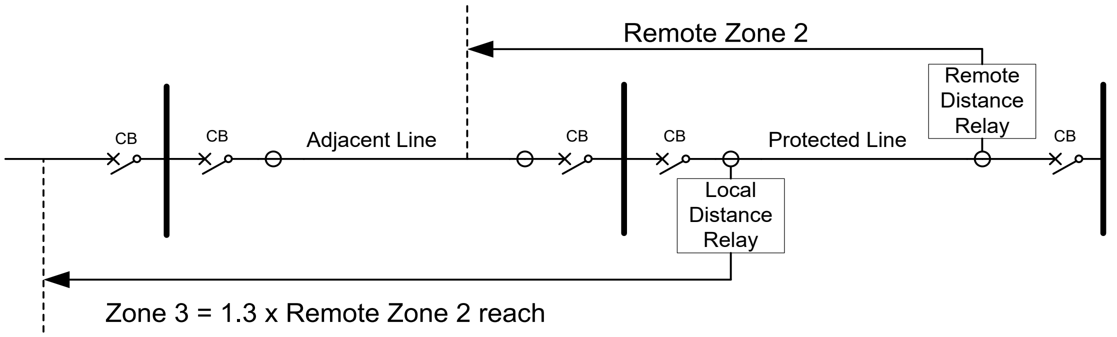
3) When used in communications aided schemes:

   When used in blocking schemes the forward direction remote zone 2 reach must not over-reach the reverse direction local zone 3 reach.

Zone 3 is typically set to 1.3 x remote zone 2 when used with blocking schemes. If remote zone 2 is a quadrilateral characteristic, zone 3 must be of same R/X ratio.

Zone 3 reach = 1.3 remote zone 2 reach

Figure 3.10 – Zone 3 reach



3.4.3.2.3.3 Zone 3 Time delay

A 2.5 second delay is standard for all remote system backup zones [34]. A fault within the roll out region of the remote zone 2 could be cleared by local zone 3 operations. Historically this delay was calculated for each setting order. After a review of the calculated delays it was noticed that 2.5 seconds provided enough margin to be used as a standard setting.

There is no attempt to coordinate zone 3 with zone 4. A fault persisting for the standard zone 3 or zone 4 delays indicates a catastrophe. If the line is contributing to the fault, tripping will mitigate the problem.

3.4.3.2.4 Zone 4

3.4.3.2.4.1 General

Zone 4 (Z3F for electromechanical relays) provides system backup protection for faults on plant beyond the end of the protected line. Zone 4 is also used to provide SOTF protection in the forward direction.

Zone 4 is set in the forward direction.

Zone 4 is active at all times.

3.4.3.2.4.2 Zone 4 reach

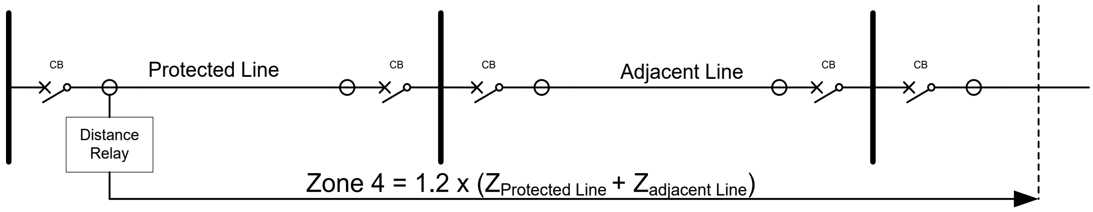
1) Lower limit

Where practical the Zone 4 reach will be set to detect all bolted faults on the longest adjacent line. Note that this setting does not necessarily need to allow for in-feed on the adjacent line. This may result in remote faults on the adjacent line to being undetected by zone 4.. This is considered acceptable because zone 4 is in addition to the Technical Rules required backup protection for the adjacent line. Both protection systems on the adjacent line would have to fail before zone 4 would be required to respond to the fault.

Zone 4 reach ≥ 1.2 x ($Z_{\text{Protected Line}} + Z_{\text{Highest Impedance Adjacent Line}}$)

[34] This time delay was formerly 1.0 or 2.0 seconds.

Figure 3.11 – Zone 4 maximum reach



2) Upper limit

It must not be possible for worst case load to encroach into the operating characteristic.

When IDMT overcurrent is provided at the remote end or load encroachment intervenes the maximum reach is:

Zone 4 reach ≤ 0.8 x ($Z_{\text{Protected Line}}$ + $Z_{\text{//\_Transformers}}$]

where $Z_{\text{//\_Transformers}}$ is the lowest possible parallel combination of transformers at the remote end that connect to a system protected by IDMT overcurrent relays.

3.4.3.2.4.3 Time delay

A 2.5 second delay is standard for all remote system backup zones [35]. A fault within the roll out region of zone 2 could be cleared by a zone 4 operation. Historically this delay was calculated for each setting order. After a review of the calculated delays it was noticed that 2.5 seconds provided enough margin to be used as a standard setting.

3.4.3.3 Instantaneous Overcurrent

Instantaneous overcurrent protection is useful when a fault close to one end of a line causes CT saturation. Sufficient saturation can delay, or prevent operation of the local differential elements. The instantaneous overcurrent elements are faster than the differential elements and may operate before the onset of saturation.

3.4.3.3.1 Two Ended Lines

The high set overcurrent pickup is set to 1.3 x the maximum fault current at the remote end of the line with the remote end CB open and at maximum generation. This means that it may not be set effectively on short transmission lines.

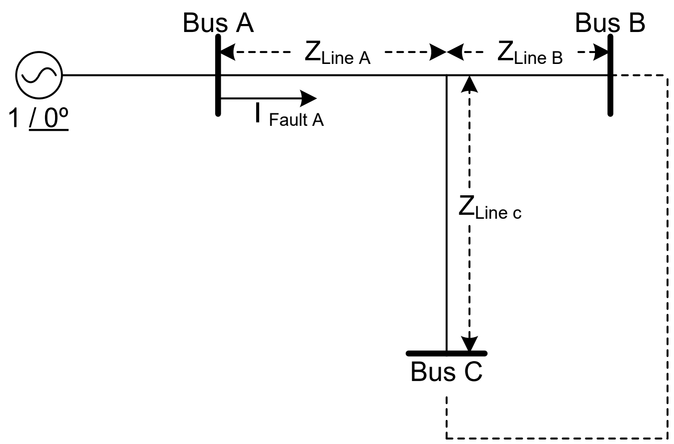
3.4.3.3.2 Teed Lines

For a teed line between substations A, B, and C the maximum fault current at bus A is given by:

$$I_{Fault_A} = \frac{1\angle 0^\circ}{Z_{Line_A} + \dfrac{Z_{Line_B} Z_{Line_C}}{Z_{Line_B} + Z_{Line_C}}} pu$$

[35] This time delay was formerly 1.0 or 2.0 seconds.

Figure 3.12 – Maximum fault level on teed lines



The high set overcurrent pickup at bus A is set to 1.3 x the maximum fault current at bus A.

3.4.3.4 IDMT Directional Earth Fault

The purpose of IDMT directional earth fault (DEF) is to detect and clear low level earth faults, below the sensitivity of the main protection system. IDMT DEF is a standard function provided on all split phase constructions.

It may be possible to coordinate IDMT earth fault relays on a system of lines using DEF elements. If DEF elements are not available the line, the earth fault function is set with a slow time multiplier similar to remote backup. Consideration must be given to the coordination of downstream earth fault protection schemes under N-1 secondary conditions when selecting the pickup and time multiplier setting (TMS). If the failure of a single downstream secondary element does not present a loss of discrimination then the following settings are selected:

1) Western Power's standard earth fault pickup is 0.1
2) Western Power's standard TMS is 0.50. This provides a definite minimum operating time range of 0.99 – 1.13 seconds, depending on the relay. This delay is considered suitable to discriminate with adjacent lines which may be equipped with high speed single pole automatic reclose (HSSPAR). Where HSSPAR is not provided a faster TMS can be used (e.g. ≥ 0.30), however DEF must never operate before the zone 2 total clearing time.

3.4.3.5 Switch On To Fault

3.4.3.5.1 Purpose

The purpose of switch on to fault (SOTF) is to respond quickly to closure of the associated circuit breaker onto a set of working earths applied to the transmission line at or very near the terminal station or zone substation.

SOTF comprises a single phase instantaneous overcurrent element supervised by voltage elements. It may also include distance elements [36].

[36] The incorporation of SOTF in electromechanical / analogue solid state distance relays using overcurrent elements bordered the impossible. Impedance starters or third zone measurers were used instead. These had overcurrent guards, typically with 0.1A – 0.2A secondary current pickups. With the last generation of these (e.g. Quadramhos) a choice of impedance starters and/or level detectors was possible. The current setting of the level detector, however, was determined primarily by the zone 1 reach and if the manufacturer's guidelines were followed, the

SOTF is applied to all lines for the following reasons:

1) Some relay elements include a capacitive inrush feature which delays them and increases their pickup during switch on conditions.
2) The sensitivity required to detect SOTF conditions may result in an excessively low setting. For security, the differential elements should be set above the maximum load plus charging current, while still detecting all line faults.
3) Faults near the substation will cause the volts to inhibit distance elements from clearing the fault.
4) The differential elements will not respond to faults outside the protected zone. Without SOTF closure onto working earths beyond the end of a line therefore needs to be detected by other elements. The backup distance protection elements typically have time delays of 1 second. For faults on the local or remote buses, fault clearance by busbar protection would be rapid. For working earths in the small zone at the remote end, clearance would be by the busbar protection, circuit breaker fail and inter-tripping which is slow.

3.4.3.5.2 Functionality

SOTF can be summarised as follows:

1) The SOTF function shall be "armed" when the circuit breaker has been opened and the standard SOTF enable time of 60 seconds has elapsed. The circuit breaker is determined to be open when:
   a) Current is below a set level in all phases and
   b) The circuit breaker auxiliary contacts indicate that the circuit breaker is open
2) The SOTF function shall be "disarmed" when the circuit breaker has been closed and the standard SOTF duration time of 0.6 seconds has elapsed. The circuit breaker is determined to be closed when:
   a) Current is above a set level in at least one phase or
   b) The circuit breaker auxiliary contacts indicate that the circuit breaker is closed
3) SOTF shall be voltage restrained unless a VT is not available. Restraint for load inrush conditions and VT failure is provided by a voltage element. Restraint for VT failure is provided by logic. Refer to section 3.4.3.8.

3.4.3.5.3 SOTF Settings

3.4.3.5.3.1 Zone 3 and Zone 4

Zone 3 and zone 4 are used for SOTF with differential schemes. The reasons for this are:

1) The elements include a capacitive inrush feature which delays them by 1 cycle and doubles their pickup during switch on conditions
2) The sensitivity required to detect SOTF conditions may result in an excessively low setting, bearing in mind that for security, the differential elements should (preferably) be set above the minimum load (+charging), whilst detecting all line faults.

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best distance reach accuracy was obtained with the minimum level detector pickup current (e.g. 50 milliamps secondary) giving the setting engineer little flexibility.

Numerical relays avoid all these problems by measuring the 50 Hz component of the current and offering any pickup over the full range of the relay. This pickup can be "ANDed" with a positive-sequence voltage to distinguish between fault current and inrush/charging current. The result can be "ORed" with zone 3 or zone 4 if required.

3) CT saturation may prevent operation of the differential elements

4) The differential elements will not respond to faults outside the protected zone. Hence, closure onto working earths beyond the end of a line will need to be detected by other elements, or protection.

3.4.3.5.3.2 Phase Time Overcurrent

Pickups are determined by the following limits:

1) The lower limit of the setting is calculated from:

   a) Phase time overcurrent pickup

   b) A margin. The SOTF margin ensures that the pickup of SOTF is above the maximum intended steady state transmission line load. This avoids the sequential event buffer being filled with uninteresting changes. Normally set to 130% of load.

   c) Relay errors.

   In practice, a small setting may be acceptable, if a very secure restraint for cold load inrush and VT failure conditions is possible [37].

2) Upper limit: 50% of the bolted 3 phase fault level at the busbar under minimum system conditions.

3.4.3.5.3.3 Phase under voltage pickup

All phase voltages must be below this setting for the phase under voltage function to pickup. The phase under voltage pickup should be:

1) Above a lower boundary just above zero. The lower the setting of pickup, the less effective the SOTF function will be. If the pickup is set close to zero, only earths placed close to the bus bar would cause SOTF to operate.

2) Below an upper boundary defined by the voltage sag caused by energising a heavily loaded, healthy transmission line.

3) A standard setting of 40% of the nominal operating voltage has been used with success. This setting:

   a) Permits working earths within the radius of interest to be detected

   b) Differentiates between load inrush current and fault current caused by working earths

A time delay is required when the VT used for SOTF restraint is energised by closing the line circuit breaker. The time delay must be sufficient to allow the protection relay time to measure voltage and restrain SOTF. Without the time delay the SOTF function could incorrectly operate for inrush.

3.4.3.6 Circuit Breaker Failure

The purpose of circuit breaker failure (CB Fail) is to detect when the tripping of a circuit breaker fails to clear its contribution to a fault. This can be caused either by the circuit breaker failing to open or by a small zone fault.

[37] Historically when voltage restraint was not used a SOTF allowance factor of 3 was used to allow for cold load inrush. A factor up to 6 would have been used if loads were known to draw large inrushes. Unrestrained SOTF operations have been experienced at settings based on 150% of maximum load.

The circuit breaker failure detection in RRST sites are to be performed by current and CB auxiliary contacts checks. This design mainly relies on CB auxiliary contacts check for the scenarios of local or remote CB fail and faults on the LV side of the RRST.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of CB Fail.

3.4.3.7 Local and Remote Metering

Refer to Engineering Design Instruction – Substation Secondary Systems Design for local and remote metering requirements.

3.4.3.8 VT Failure

The purpose of VT failure is to distinguish between two distinct conditions. Both of these conditions result in a disturbance or loss of secondary volts from the VTs to the relay. The two conditions are:

1) Primary system fault conditions such as:

   a) Phase to earth faults

   b) Phase to phase faults

   c) Three phase faults

   Under these conditions the relay must recognise that a primary fault exists and operate.

1) Non primary system fault conditions such as:

   a) VT primary isolated by primary switching or primary fuse operation

   b) VT secondary disturbed by secondary fuse, or MCB operation

   c) Secondary wiring interference

   d) Disturbance at the test links

   e) Secondary wiring fault

   Under these conditions the relay must recognise that a fault does not exist and not operate. The protection relay may need to take steps to restrain some protection functions.

3.4.3.8.1 Alarming

The VT is used to calculate fault impedance, restrain protection functions and for metering. It is therefore important to alarm for a VT No primary system fault exists and

A secondary system fault does exist.

3.4.3.9 Circuit Breaker Wear Monitoring

The purpose of circuit breaker wear is to assist in the scheduling of circuit breaker maintenance. If a transmission line protection relay is used to control a circuit breaker, it must also provide circuit breaker wear monitoring.

Settings are chosen to allow the relay to calculate and accumulate circuit breaker wear information during each circuit breaker opening action.

It is important to preserve accumulated breaker monitoring information during routine maintenance. Therefore it is a requirement that maintenance staff be provided with a means of temporarily disabling the recording of such data.

3.4.3.10 Trip Circuit Supervision

The purpose of trip circuit supervision (TCS) is to supervise the integrity of the circuit breaker trip coil. The trip coil is supervised when in both the open and closed state. TCS also supervises the integrity of some of the associated secondary wiring

Refer to Engineering Design Instruction – Substation Secondary Systems Design for a detailed description of TCS.

3.4.3.11 Dynamic Disturbance Recorder

The dynamic disturbance recorder (DDR) must be configured so that the recorder captures the:

1) Pre fault waveforms.

2) Post fault waveforms which include circuit breaker failure operations.

3) Post fault waveforms which include clearance by downstream devices within the main protection system operating zone.

3.4.3.12 Sequence of Events Recorder

The sequence of events recorder (SER) monitors what occurs within the relay during both normal operation and faults. When the SER is triggered, a record is created of these events. A protection trip must trigger the SER.

To simplify the event record and minimise the chance of the relay failing, the following guidelines should be followed when choosing what is to appear in the SER:

1) Do not include word bit outputs of directional elements

2) Do not include word bits that may change state frequently under normal conditions, or near the edge of such conditions

3.4.3.13 Time Synchronisation

The protection relays must be configured to receive the Irig B time code or the SNTP time signal when available. The Irig B clock and the SNTP server provide accurate time stamping for fault events. Irig B is more accurate and preferred when no additional wiring is required.

Irig B is standard for all DNP relays. Irig B is standard on IEC61850 relays when additional wiring is not required (e.g. zone substation HV relays). When additional wiring is required SNTP is used (e.g. zone substation LV relays).

3.4.3.14 Defective Alarms

Protection defective means the protection scheme is defective. At DNP sites this is hardwired from the IED to the RTU and means that the IED is defective. At IEC61850 sites it includes failure of the IEC61850 signalling.

Device defective means that the hardware is defective. Examples include IEDs, controllers and gateways.

Defective alarms use normally open contacts when hardwired.

3.4.4 Main Protection Systems Site Specific Functions

3.4.4.1 Delayed Automatic Reclose

The purpose of delayed automatic reclose (DAR) is to automatically restore supply following a transient fault. DAR trips and closes all three circuit breaker poles at once (3 pole tripping).

DAR must be taken out of service when:

1) The operator selects the local / remote switch on the circuit breaker to the local position
2) The circuit breaker mechanism is defective

Refer to Section 8 – Circuit Breaker Protection for a detailed description of DAR.

3.4.4.2 High Speed Single Pole Automatic Reclose

The purpose of high speed single pole automatic reclose (HSSPAR) is to automatically restore supply following a transient fault. HSSPAR trips and closes each pole independently (single pole tripping). The line protection must provide phase segregated tripping and CB fail initiate.

HSSPAR must be taken out of service when:

1) The operator selects the local / remote switch on the circuit breaker to the local position
2) The circuit breaker mechanism is defective

Refer to Section 8 – Circuit Breaker Protection for a detailed description of HSSPAR.

3.4.4.3 Check Synchronisation

The purpose of check synchronisation (check sync) is to prevent unsynchronised systems from being closed onto each other.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of check sync.

3.5 Appendix A – Transmission Line and Cable Design Requirements

Functions		Operation						Indication					
Function Name	**ANSI**	**Initiation**		**Selection**		**Resetting**		**Operation**		**Selection**		**Resetting**	
		A/R	**CB Fail**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**Self**
Distance	21	Yes	Yes			Self		Yes	Yes			Yes	
Differential	87	Yes	Yes			Self		Yes	Yes			Yes	
Highset instantaneous overcurrent	50		Yes			Self		Yes	Yes			Yes	
Directional earth fault time overcurrent	64	Yes	Yes			Self		Yes	Yes			Yes	
Switch on to fault	SOTF		Yes			Self		Yes	Yes			Yes	
CB failure	52					Latched		Yes	Yes			Yes	
Local metering	HMI												
Remote metering	77												
VT failure	47					MCB		Yes	Yes				
Circuit breaker wear monitoring	94.1			Yes						Yes			
Trip circuit supervision	TCM					Self		Yes	Yes				Yes
Dynamic disturbance recorder	DDR												
Sequence of events recorder	SER												
IRIG B	CLK								Yes				Yes
Protection defective						Self		Yes	Yes				Yes
Device defective						Self		Yes	Yes				Yes
DAR	79			Yes	Yes	Self		Yes	Yes	Yes	Yes		Yes

HSSPAR	79			Yes	Yes	Self		Yes	Yes	Yes	Yes		Yes
Out of step blocking	68					Self		Yes	Yes				Yes
Fault Locator						Self		Yes	Yes				Yes
Check synchronism defective	25					Self		Yes					
Intertrip Send / Receive						Yes		Yes	Yes				Yes

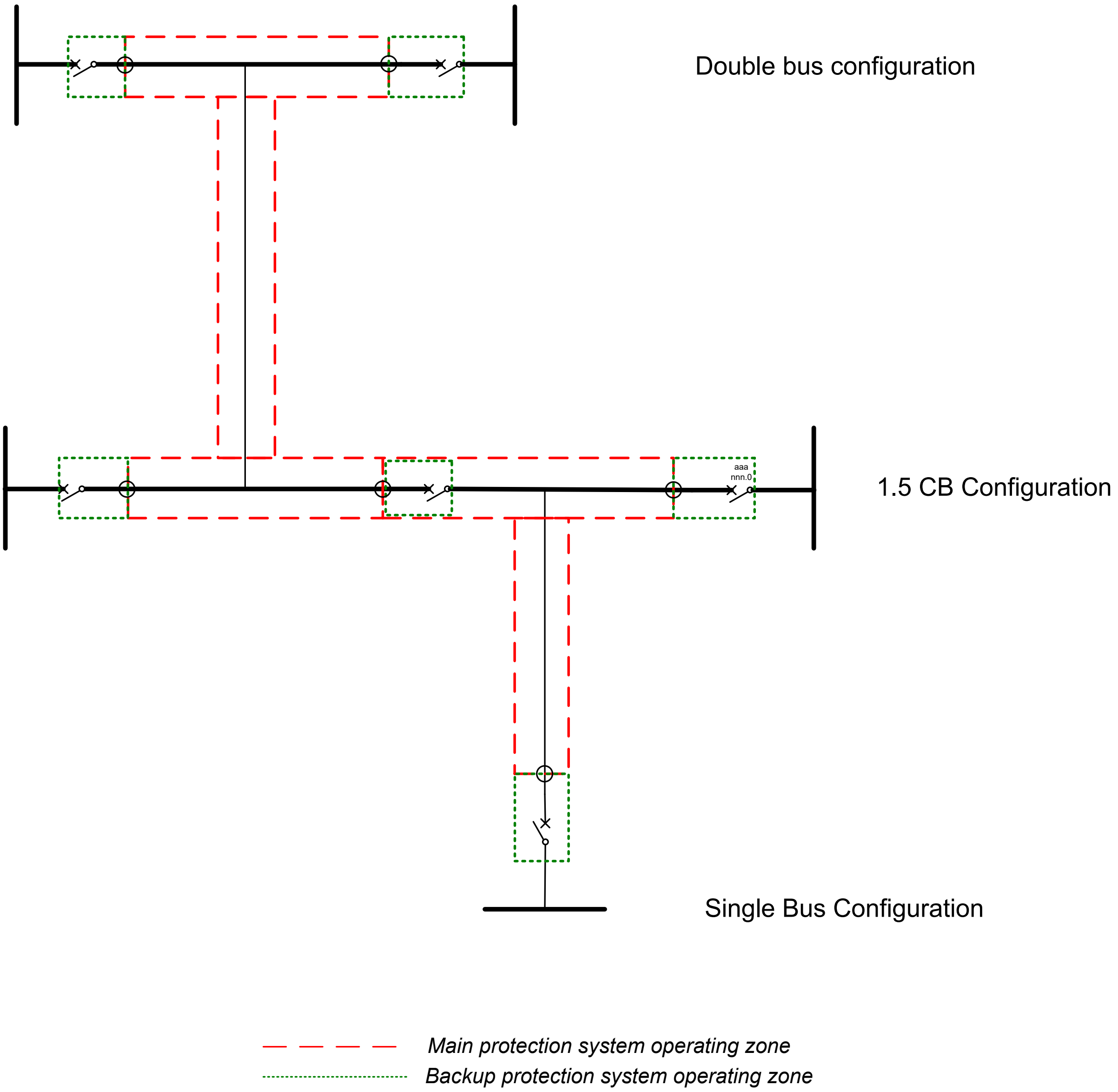
Note: Grey areas signify ‘No’ or ‘Not Applicable’

Note: Relay Resetting includes both contact and word bit resetting

Note: Resetting requirements above are for lines only. Cable protection operations are always latched

3.6 Appendix B – Roles and Responsibilities

3.7 Appendix C – Transmission Line and Cable Operating Zones



3.8 Appendix D – Advantages / Disadvantages

3.8.1 Main Protection Schemes Advantages / Disadvantages

3.8.1.1 Differential / Distance

Advantages of this option include:

1) Different operating principles

Disadvantages of this option include:

1) As a unit protection, the differential protection scheme only detects and clear faults within the operating zone. They do not provide system backup protection past the operating zone. For this reason time stepped distance element shall always be utilised in addition to the differential element.

2) Distance reaches can be difficult to set on teed transmission lines to achieve required total fault clearance times.

3.8.1.2 Differential / Differential

Advantages of this option include:

1) Used on teed transmission lines to overcome reach problems with distance schemes

2) Used on short lines where distance protection schemes cannot be used effectively

Disadvantages of this option include:

1) As a unit protection, differential protection schemes only detect and clear faults within the operating zone. They do not provide system backup protection past the operating zone.

2) Similar operating principle

3.8.1.3 Distance / Distance

Advantages of this option include:

1) Can be used to provide backup protection for primary equipment outside of the transmission line operating zone

2) Close in faults cleared quickly

Disadvantages of this option include:

1) Distance reaches can be difficult to set to achieve required total fault clearance times on teed transmission lines

2) Similar operating principle. This can be minimised by utilising interlocked distance schemes based on differing operating principles.

3.8.2 Interlocking Schemes Advantages / Disadvantages

Advantages	POR	PUR	BOR	BUR
There is a greater tolerance to high impedance faults since over reaching elements are used. High speed clearance will occur for any faults detected by the overreaching elements.	X		X	
There is a greater tolerance to high resistance faults than with a normal time stepped distance scheme since the zone 1 element at only one end is required to pick up to give high speed fault clearance				X
The scheme is more tolerant to errors on the communications channel, than a direct inter-tripping scheme, since the signal is checked by local measurement.	X	X	X	X
With independent zone 1 and 2 elements, high speed clearance of faults can still occur with the loss of the signalling channel as it reverts to a normal time stepped distance scheme. Thus provided high speed clearance over the entire line is not required for coordination, coordination will not be lost. There may however be cases where the zone 2 elements of other lines overlap in which case the signalling channel is required for coordination.	X	X		
This scheme can be used on short lines due to its tolerance to high resistance faults. Also the distance relay does not need to be set to less than the line impedance. Setting a relay to less than the line impedance can be a problem on very short lines.	X			
Independent signalling channels are not required since a permissive signal is only sent if the relay gives a trip output.		X		
The scheme can be applied to teed lines provided the possible slower clearance can be tolerated (short time lag)			X	X
The scheme can be used lines with weak or no in-feed without any added logic.			X	X
High speed fault clearance is achieved over the entire line length			X	X
A dual signalling channel is not required			X	

Disadvantages	POR	PUR	BOR	BUR
Independent signalling channels are required in each direction.	X			X
Where independent zone 1 and 2 elements are not available, slow clearance of faults will occur upon the loss of the signalling channel. This will generally result in the loss of coordination for some faults.	X			
Fast clearance of faults is dependant upon the over reaching elements of the distance relays at both ends of the line seeing the fault. If there is a weak or no source at one end, resulting in the relay not seeing the fault, or the remote circuit breaker is open, then a permissive signal will not be sent from that end and slow clearance will result. This can however be overcome by the use of a weak in-feed scheme.	X	X		
The scheme will may not provide high speed clearance for teed lines.	X	X		
If the fault is not seen by zone 1 from at least one end the fault clearance will be slow. Thus the tolerance to high resistance faults is not as high as with an over reaching scheme		X		
Coordination can be lost on failure of the signalling channel			X	X
Coordination can be lost for some high resistance faults if the forward reach of the zone 3 element cannot be set as far as the remote line end.			X	X

Some relays are not suitable for a blocking scheme if the forward reach of the zone 3 cannot be set as far as the remote line end.			X	X

3.8.3 Stub Protection Advantages / Disadvantages [38]

Advantages of providing stub protection include:

1) The line remains energised from the remote end and in service for a stub fault.

2) The circuit breakers do not trip for a line fault.

3) A less sensitive overcurrent setting may be possible to better guard against heavy through fault currents.

Disadvantages of providing stub protection include:

1) Enabling stub protection adds complexity without significant operational gain. Stub faults are rare and if a bay is opened for a line fault, the bay can generally be re-meshed.

2) Depending on how the stub protection is implemented a faulty disconnector auxiliary contact may trip the remote ends.

3) There is possible confusion when stub / logout mode interacts with local maintenance test (LMT) mode.

4) Some relays block all intertrips when in stub mode. These intertrips may be configured for special schemes such as runback schemes which operate independently of the disconnector status.

[38] Digital Differential Enhancements and Scheme Standardisation,

3.9 Appendix E – Main Protection Scheme Selection

Number of high speed protection schemes is determined by the following requirements:

1) Critical fault clearance times
2) Technical Rules maximum total fault clearance times
3) Discrimination

Number of high speed schemes required	Teed Line OR HSSPAR[1]	Short line (<5 km)	Weak In-feed Possible [2]	Communication 1 Available	Communication 2 Available	Protection 1	Protection 2
0	No	No	No	None	None	Time Stepped Distance	Time Stepped Distance
			Local OR Remote End	Digital	Digital	Digital Differential [5]	Digital Differential [5]
				Digital	Analogue	Digital Differential	Permissive Overreach
				Analogue	Analogue	Permissive Overreach	Permissive Overreach
				Digital	Power Line Carrier	Digital Differential	Unblock
				Analogue	Power Line Carrier	Permissive Overreach	Unblock
			Local AND Remote Ends [3]	Digital [4]	Digital [4]	Digital Differential [5]	Digital Differential [5]
		Yes	N/A	Digital [4]	Digital [4]	Digital Differential [5]	Digital Differential [5]
	Yes	N/A	N/A	Digital [4]	Digital [4]	Digital Differential [5]	Digital Differential [5]
1	No	No	No	Analogue	None	Permissive Overreach	Time Stepped Distance
						Blocking	Time Stepped Distance
				Digital	None	Digital Differential	Time Stepped Distance
			Local OR Remote End	Digital	Digital	Digital Differential [5]	Digital Differential [5]
				Digital	Analogue	Digital Differential	Permissive Overreach
				Analogue	Analogue	Permissive Overreach	Permissive Overreach
				Digital	Power Line Carrier	Digital Differential	Unblock
				Analogue	Power Line Carrier	Permissive Overreach	Unblock
			Local AND Remote Ends [3]	Digital [4]	Digital [4]	Digital Differential [5]	Digital Differential [5]
		Yes	N/A	Digital [4]	Digital [4]	Digital Differential [5]	Digital Differential [5]
	Yes	N/A	N/A	Digital [4]	Digital [4]	Digital Differential [5]	Digital Differential [5]
2	No	No	No	Analogue	Analogue	Permissive Overreach	Blocking
				Digital	Analogue	Digital Differential	Permissive Overreach
				Digital	Digital	Digital Differential [5]	Digital Differential [5]
				Digital	Power Line Carrier	Digital Differential	Unblock
				Analogue	Power Line Carrier	Permissive Overreach	Unblock
			Local OR Remote End	Digital	Digital	Digital Differential [5]	Digital Differential [5]
				Digital	Analogue	Digital Differential	Permissive Overreach
				Analogue	Analogue	Permissive Overreach	Permissive Overreach
				Digital	Power Line Carrier	Digital Differential	Unblock
				Analogue	Power Line Carrier	Permissive Overreach	Unblock
			Local AND Remote Ends [3]	Digital [4]	Digital [4]	Digital Differential [5]	Digital Differential [5]
		Yes	N/A	Digital [4]	Digital [4]	Digital Differential [5]	Digital Differential [5]
	Yes	N/A	N/A	Digital [4]	Digital [4]	Digital Differential [5]	Digital Differential [5]

1) Two high speed protections are required with HSSPAR applications to ensure that the circuit breaker operations at each end of the faulted line are as simultaneous as possible
2) 'Weak In-feed Possible' does not include 'No In-feed'
3) This includes both line ends being subjected to a weak in-feed for the same network configuration
4) Digital communications is required under these conditions
5) Duplicate differential protection is considered acceptable because, when possible, time stepped distance is always implemented with differential protection.

4 Busbar Protection

4.1 Introduction

The purposes of this section are to:

1) Define at a high level the functional requirements for busbar protection in Western Power terminal stations and zone substations

2) Capture information which explains the reasoning behind the busbar protection design and settings

4.2 Scope

This section applies to busbar protection in Western Power terminal stations and zone substations.

4.3 Functional Requirements

The functional requirements of the busbar protection system are:

1) Detect and clear faults in the busbar operating zone

2) Detect and clear faults within times specified by the Technical Rules

4.4 Busbar Protection

4.4.1 Introduction

The main purpose of the busbar protection system is to minimise danger to staff and damage to equipment by clearing faults on the busbar.

The detection of faults by detecting differential currents is widely used for protection of many types of primary equipment including busbars. Differential protection is based on the principle that the current entering a non-faulted object equals the current leaving the object.

Current transformers (CT) are located on all circuits connected to the busbar that can carry current into or out of the busbar. The current transformers define the busbar protection's operating zone. A fault within the operating zone will make the current entering the operating zone higher than the current leaving. The difference in currents is called the differential current. The protection relay detects the differential current and issues a trip command if the magnitude of the differential current is above the set threshold.

4.4.1.1 Protection Schemes

4.4.1.1.1 High Impedance Current Measuring Relays

Current measuring relays have a coil which is energised by a tapped transformer. The transformer taps are selected via a bridge and provide the current setting of the relay (I_{Set}). When the current through the coil (I_{Relay}) reaches the setting value, I_{Set}, the relay operates.

For external through fault stability, the extreme case where one CT fully saturates and the other CTs have no saturation is considered. The fully saturated CT is modelled with its magnetic impedance short circuited, thus driving no current. The operating voltage V_{OP} must be high enough so that the relay does not operate for a through fault with CT saturation.

The value of R_{Series} and the relay resistance determine the operating voltage (V_{OP}). The operating voltage can therefore be set higher than the voltage across the saturated CT and leads by increasing R_{Series}. Increasing R_{Series} reduces the amount of current through the relay, I_{Relay}, to less than the setting, I_{Set}. This prevents incorrect operation for through faults with a saturated CT.

R_{Series} must also be selected so that V_{OP} is below ½ the lowest CT knee point.

Figure 4.1 – Equivalent Circuit: Current measuring relay with a through fault

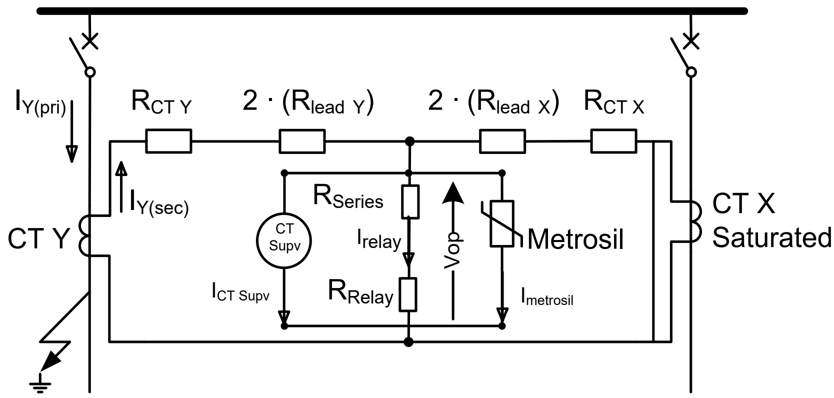
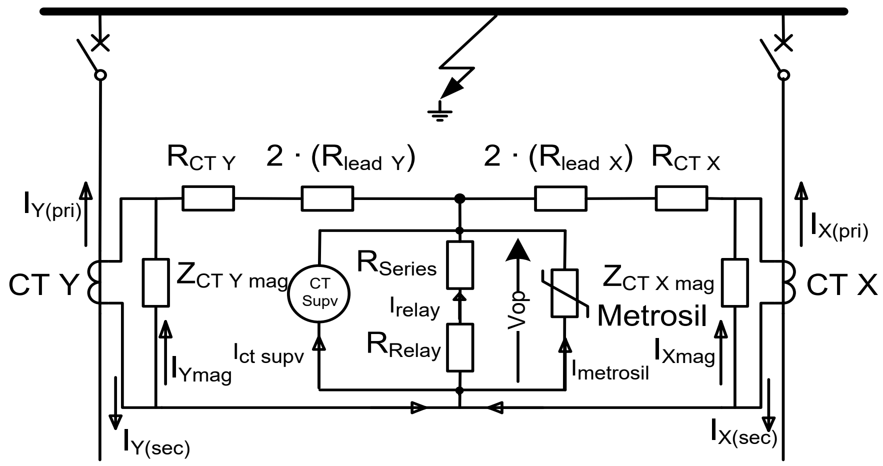


Figure 4.2 – Equivalent Circuit: Current measuring relay with an in-zone fault



4.4.1.1.2 *High Impedance Voltage Measuring Relays*

Voltage measuring relays have a selectable voltage setting, V_{Set}. When the voltage across the relay, V_{OP}, reaches V_{Set} the relay operates. The voltage setting must be above the voltage which develops across the leads and a saturated CT. This allows stability for through faults. V_S must also be below ½ the lowest CT knee point.

The impedance of the relay coil may limit the primary operating current (I_{POC}) to a level below the design requirements. A shunt resistor (R_{Shunt}) is therefore usually installed. R_{Shunt} can be used to:

1) Increase the primary operating current

2) Decrease V_{OP} to less than ½ the lowest CT knee point by providing a parallel path for current

3) Increase V_{OP} above the voltage developed across the lead and saturated CT resistance for stability during through faults

Figure 4.3 – Equivalent Circuit: Voltage measuring relay with a through fault

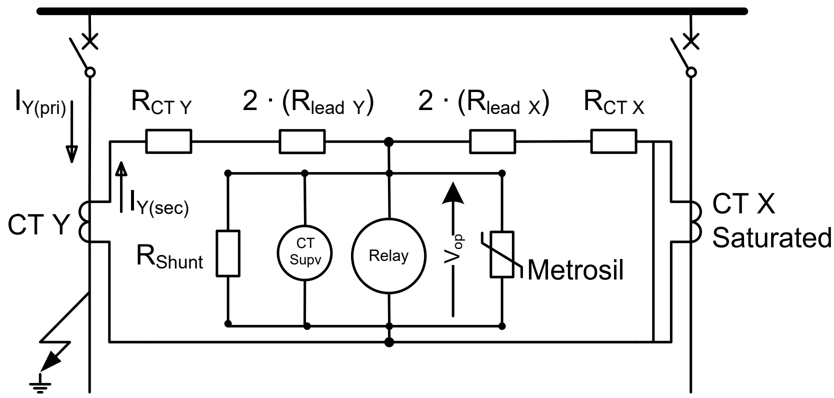
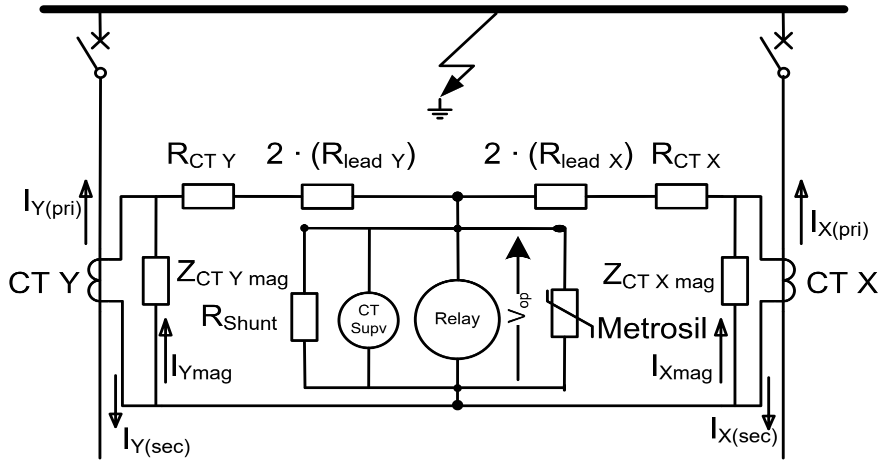


Figure 4.4 – Equivalent Circuit: Voltage measuring relay with in-zone fault



4.4.1.1.3 Low Impedance Differential Protection

Low impedance busbar protection schemes consist of numerical relays that measure individual circuit currents and determine the differential current numerically. Low impedance differential protection schemes incorporate a bias element to increase security for through faults.

4.4.2 Design Requirements

Section 4.5 outlines the design requirements for standard functions and site specific functions.

4.4.2.1 Distribution Main Protection System

4.4.2.1.1 Indoor Switchgear with Busbar Protection

The busbar main protection system operating zone is defined by the current transformers on circuits connected to the busbar. Refer to Section 4.7 – Appendix C – Operating Zones.

The selection of the busbar protection system is based on the lowest life cycle cost. Refer to Appendix E – Advantages / Disadvantages for the advantages and disadvantages of each option.

Table 4.1 – Indoor Switchboard Main and Second Protection Systems

Option	Main Protection System	Second Protection System
1	High Impedance	Transformer HV IDMT overcurrent
2	Low Impedance	Transformer HV IDMT overcurrent

1) High impedance scheme. These schemes are preferred for all applications except double busbar configurations. It is not always possible for the transformer LV protection system to back up a feeder protection scheme. In the case where there is lack of sensitivity for a single feeder it is more cost effective to install a second feeder protection relay than a low impedance busbar scheme.

2) Low impedance scheme. Low impedance schemes are preferred for:

   a) Double busbar applications. This is because high initial hardware costs are significantly offset by higher security against incorrect operation due to faulty disconnector auxiliary contacts.

   b) When lack of available CT cores are a problem. Low impedance busbar protection can perform other functions (e.g. IDMT overcurrent).

   The current low impedance relay only has enough AC inputs for 6 circuits. Use of multiple low impedance relays to protect a busbar with many connected circuits is possible but not cost effective. It is preferred not to parallel circuits because the relays do not bias the contributions.

4.4.2.1.1.1 Existing Outdoor Switchgear with no Busbar Protection

The transformer LV protection provides the busbar main protection system. Note that the transformer LV protection system must grade with the feeder protection systems. It therefore will generally not meet clearance time requirements for a main protection scheme. For this reason a busbar protection system is installed for all new busbars.

4.4.2.2 Distribution Backup Protection System

The backup protection system's operating zone includes small zone faults in addition to the main protection system operating zone. Refer to Section 4.7 – Appendix C – Operating Zones.

The backup protection system for new and existing sites is comprised of:

1) The transformer HV protection system. Specifically, the transformer HV overcurrent provides backup protection for the busbar's main protection or transformer LV protection system. The transformer HV protection also detects and clears small zone faults on circuits connected to the LV busbar.

2) Feeder IDMT overcurrent protection. IDMT overcurrent is not directional and therefore may operate for fault current supplied from the distribution system. An example of this would be feeders with embedded generation.

3) The transformer LV standby earth fault (SBEF) provides backup for busbar earth faults.

4.4.2.3 Transmission Main Protection System

The operating zone of the main protection system is defined by the current transformers connected to the busbar.

The selection of the type of main protection scheme is based on the lowest life cycle cost.

Table 4.2 – Transmission Main Protection Schemes

Option	Main Protection Scheme	Use
1	High Impedance	All applications except double busbar configurations.
2	**Low Impedance**	**Double busbar applications. The high initial hardware costs are significantly offset by higher security against incorrect operation due to faulty disconnector auxiliary contacts**

4.4.2.4 Transmission Backup Protection System

The operating zone of the backup protection system includes small zone faults in addition to the main protection system operating zone. The requirements for the backup protection depend on the voltage level.

Western Power's preference is for duplicated circuit breaker failure schemes at all transmission voltages to:

1) Meet local total fault clearance time requirement
2) Allow the system to be reconfigured in the future without affecting the backup protection system
3) Minimise risk of blacking out a terminal station for a remote backup operation

4.4.2.5 Relay Reset Requirements

A protection device that sends a trip signal for busbar faults shall:

1) Latch
2) Retain its state when powered down

4.4.2.6 Stability

A busbar protection operation will result in the tripping of many circuits. For this reason priority is given to stability of the scheme for through faults and the effects of CT spill and saturation. In general, the maximum possible relay setting, which still meets Western Power's sensitivity requirement, is chosen to provide this stability.

4.4.2.7 CT Polarity

For the busbar protection scheme to operate correctly the secondary terminals of the CTs must be connected correctly with regard to polarity. When connected correctly the currents leaving the protected object are subtracted from the currents entering for a through fault or load. When not connected correctly the currents leaving add to the currents entering causing an incorrect operation. The requirement is that all bus-zone CT star points either face the busbar or all star points face away from the busbar. Western Power's policy for new sites is:

1) Zone substation busbar schemes – The star points face away from the busbar.
2) All other plant – The star point faces toward the item of plant being protected. This includes terminal station busbar and inter-zone schemes, transformers and non-unit protection.

When adding new circuits to an existing busbar scheme, the polarity of the new CT must be the same as the existing CTs.

4.4.2.8 High Impedance Schemes

High impedance schemes are simple in design, cost effective and proven reliable. They are used for single bus and 1.5 CB configurations. They are not used for:

1) Double busbar configurations. These configurations require a check zone and discrimination zones which depends on disconnector auxiliary contacts. Low impedance scheme relays have the ability to monitor the disconnector auxiliary contacts and are therefore preferred.

2) Sites with feeder sensitivity issues. Low impedance scheme relays have the facility to monitor the currents of individual feeder circuits. This allows them to provide the feeder's second protection system when the transformer LV protection system cannot.

4.4.2.8.1 General

The protection design and relay setting must meet the following Western Power requirements:

1) The minimum CT knee point voltage must be at least twice the operating voltage

2) The primary operating current (I_{POC}) must:

    a) Be less than half the minimum fault current which we require the scheme to detect.

    b) Be greater than 1.3 times the worst spill current arising due to CT errors.

    c) Where CT supervision is not being used, be approximately 25% of the CT primary rating. This is to let the busbar protection operate for a problem with the CT secondary wiring under reasonable load current. The busbar operation will both de-energise the problem CT and alert the East Perth control centre (EPCC) to the problem.

    d) Where CT supervision is being used, be greater than load current. This is to avoid alarming under normal conditions.

3) The resistor power rating must be adequate under the following conditions:

    a) The scheme is being tested.

    b) The current through the resistor is just under the relay operating current.

    c) This current is maintained indefinitely.

4) The operating voltage of the metrosil must be limited to 80% of its rating to:

    a) Provide safety for the maintenance people involved in the testing of the primary operating current

    b) Avoid large metrosil currents affecting the primary operating current

    High fault currents can result in dangerously high voltages across the busbar protection relay. The metrosil is a non-linear resistor that clamps the voltage by becoming a low resistance path as the current increases.

5) The maximum loop resistance must be calculated. The actual loop resistance is checked against this value at commissioning.

6) The minimum and maximum primary operating current must be calculated. These are used by commissioning as a guideline for testing.

4.4.2.8.2 Existing Busbar Schemes

Adding a new circuit to an existing busbar protection system requires that the protection design engineer check that the busbar protection system still meets the general requirements outlined above. The following setting checks must be made:

1) When adding a new circuit to an existing high impedance scheme the ratio should match the existing CTs. For situations where an exact ratio match is not possible, an interposing CT (IPCT) may be used.

2) The lowest knee point of the CTs in the busbar scheme is used to calculate the maximum operating voltage. If the new CT knee point is less than the lowest existing knee point, the new CT knee point must be used to calculate the maximum allowable operating voltage. The busbar protection operating voltage must be less than this value.

The new CT magnetising current must be added to the Primary Operating Current (POC). The recalculated POC must meet Western Power's sensitivity requirements. Refer to Section 16 – Protection Sensitivity.

4.4.2.8.3 Resistors

4.4.2.8.3.1 Series Resistor (Current Measuring Schemes)

The series resistor, R_{Series}, in current measuring schemes is used to adjust I_{Relay} to a value less than I_{Set} for through faults with CT saturation. For maximum stability the value of R_{Series} is chosen to allow:

1) The operating voltage, $V_{OP,}$ to be equal to or less than ½ the minimum CT knee point voltage and

2) The primary operating current, I_{POC}, to meet Western Power's sensitivity requirements

4.4.2.8.3.2 Shunt Resistor (Voltage Measuring Schemes)

The shunt resistor, R_{Shunt}, in voltage measuring schemes is used to adjust I_{POC} to a value which meets the design requirements in Section 4.4.1.1.2. R_{Shunt} is also used to adjust V_{OP} to be greater than V_{Set} for through faults with CT saturation. For maximum stability the value of R_{Shunt} is chosen to allow:

1) V_{Set} to be equal to or less than ½ the minimum CT knee point voltage.

2) Allows I_{POC} to be 1.3 times the worst case spill arising from CT errors.

4.4.2.8.3.3 Standard Resistor Values

When possible the resistor values must be selected from the following Western Power stock:

500 ohm, 500 Watt

720 ohm, 350 Watt

1000 ohm, 200 Watt

Note -/+ 5% tolerance in standard resistor used by Western Power.

4.4.2.8.4 Interposing Current transformers

When a new circuit is added to an existing busbar scheme it is not always possible to match the ratio of the existing CTs. When an IPCT is used, the IPCT must not limit the performance of the busbar protection. The following checks ensure this:

1) The effective turn ratio of the primary CT and IPCT is the same as the turn ratio of the existing CTs.

2) The knee point of the IPCT must be at least equal to V_{Set} for voltage measuring relays and V_{OP} for current measuring relays.

3) The current necessary to magnetise the IPCT and primary CT must be added to the POC calculations.

4.4.2.8.5 CT Supervision

CT Supervision shall be used where the state of the disconnector auxiliaries can influence the performance of the busbar protection system. During switching the circuit may be connected to the wrong busbar protection scheme due to a disconnector auxiliary switch malfunction. The check scheme prevents tripping in this situation so the problem would not be apparent. CT Supervision provides an alarm indicating a problem with the CT secondary wiring.

4.4.2.9 Low Impedance Schemes

If both of the main protection schemes use low impedance relays, they must be sourced from different manufacturers and be based on different hardware and different algorithms.

Low impedance schemes may be used under the following conditions:

1) Double busbar configurations. The low impedance relay monitors the disconnector auxiliary switch status and condition. Busbar configurations can be changed in the logic rather than the hard wiring.

2) At sites with feeder sensitivity issues. The low impedance relay can monitor individual feeders and provide the second feeder protection system.

4.4.2.10 Frame Earth Leakage Schemes

Frame earth protection schemes provide some busbar protection without the need for separate CT cores required for the differential schemes. Because modern switchboards can accommodate the required CT cores, the frame earth leakage schemes are considered obsolete.

When working with frame earth leakage switchboards the switchboard must be insulated from earth except through the frame leakage CT neutral. This means that there must be insulation:

1) Between the switchboard and where it is mounted

2) In the cable terminations (specifically the cable screen earth)

Existing frame earth leakage schemes have a poor performance record. This is due to the fact that they can easily be compromised by the incorrect installation of earths. For this reason they are not used for new installations.

Adding a new switchboard to a site with an existing frame earth switchboard will generally require running a cable between the new switchboard and the existing switchboard. Because there will generally not be a CT core available in the frame earth switchboard, the cable will not be included in a busbar scheme.

4.4.2.11 Directional Comparison Blocking Schemes

Directional blocking schemes are found on double busbar configurations. These schemes use directional overcurrent relays to detect busbar faults.

For normal load or through faults the direction of current is into the busbar from transformers and out of the busbar to feeders and bus sections. When the currents are in these directions the directional overcurrent relays send a blocking signal to the busbar protection scheme. When the currents are not in these directions, the blocking signal is not sent causing the busbar protection system to trip the circuit breakers connected to the busbar.

An advantage of these schemes is that they utilise the overcurrent CT cores. They do not require a separate CT core on each circuit for the busbar protection system.

Disadvantages of these schemes are:

1) They are very complicated

2) Result in slower clearance times than high or low impedance schemes.

For these reasons they are not used for new installations.

4.4.3 Main Protection System Standard Functions

4.4.3.1 High Impedance Schemes

4.4.3.1.1 Current Measuring Relays

4.4.3.1.1.1 Current Setting

1) Lower limit:

   The current setting (I_{Set}) in current measuring relays must be above the spill current that occurs under maximum through fault conditions. All CTs are PX class therefore the maximum turns ratio error is ±0.25% [39]. The worst case is with one CT having a -0.25% turns ratio error and the other a +0.25%. The maximum spill current that can flow into the relay is then ±0.5% of the maximum through fault current on the busbar. I_{Set} must be at least 1.3 times this value.

2) Upper limit:

   The relay current setting (I_{Set}) must meet Western Power's sensitivity requirements. Refer to Section 16 – Protection Sensitivity.

4.4.3.1.2 Voltage Measuring Relays

4.4.3.1.2.1 Voltage Setting

1) Lower limit:

   Western Power's minimum voltage setting is 50 V.

2) Upper limit:

   The relay voltage setting (V_{Set}) in voltage measuring relays must be less than or equal to ½ the minimum CT knee point voltage.

[39] AS 61869.2 – 2021

4.5 Appendix A – Busbar Design Requirements

Functions		Operation						Indication					
Function Name	**ANSI**	**Initiation**		**Selection**		**Resetting**		**Operation**		**Selection**		**Resetting**	
		A/R	**CB Fail**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**Self**
High Impedance													
Differential	87		Yes					Yes	Yes			Yes	
Trip Relay						Latched		Yes	Yes			Yes	
Supply Supervision						Self		Yes	Yes				
Low Impedance													
Differential	87		Yes			Latched		Yes	Yes			Yes	
Protection Defective						Self		Yes	Yes			Yes	
Device Defective						Self		Yes	Yes			Yes	

Note: Grey areas signify 'No' or 'Not Applicable'

Note: Relay Resetting includes both contact and word bit resetting

4.6 Appendix B – Formula

4.6.1 High Impedance Formula

The following formulas are useful in designing and setting high impedance busbar protection systems

4.6.1.1 Current Measuring Relays

$$R_{\text{Relay}} = \frac{\text{VA}_{\text{Relay}}}{I_{\text{Set}}^2}$$

$$V_{\text{OP}} = I_{\text{Set}} \cdot \left(R_{\text{Series}} + R_{\text{Relay}}\right)$$

$$I_{\text{POC}} = I_{\text{Relay and series resistor}} + I_{\text{Metrosil}} + I_{\text{CT\_Supv}} + I_{\text{Mag\_Total}}$$

The maximum loop resistance of a CT plus leads for any one CT in the group can be calculated from the following equation:

$$R_{\text{Loop\_Max}} = \frac{1}{1.21615} \cdot \left(\frac{V_{\text{Op}}}{\left(\frac{I_{\text{F\_Max}}}{N}\right)} \right)$$

Where $\frac{1}{1.21615}$ is a factor to convert resistance from Ohms at 75° C to Ohms at 20° C.

4.6.1.2 Voltage Measuring Relays

$$R_{\text{Equivalent}} = \frac{\left(R_{\text{Shunt}} + R_{\text{CT Supv}} + R_{\text{Relay}} + R_{\text{Metrosil}}\right)}{\left(R_{\text{Shunt}} \cdot R_{\text{CT Supv}} \cdot R_{\text{Relay}} \cdot R_{\text{Metrosil}}\right)}$$

$$V_{\text{OP}} = R_{\text{Equivalent}} \cdot I_{\text{Differential}}$$

$$I_{\text{POC}} = I_{\text{Relay}} + I_{\text{Metrosil}} + I_{\text{Shunt}} + I_{\text{CT\_Supv}} + I_{\text{Mag\_Total}}$$

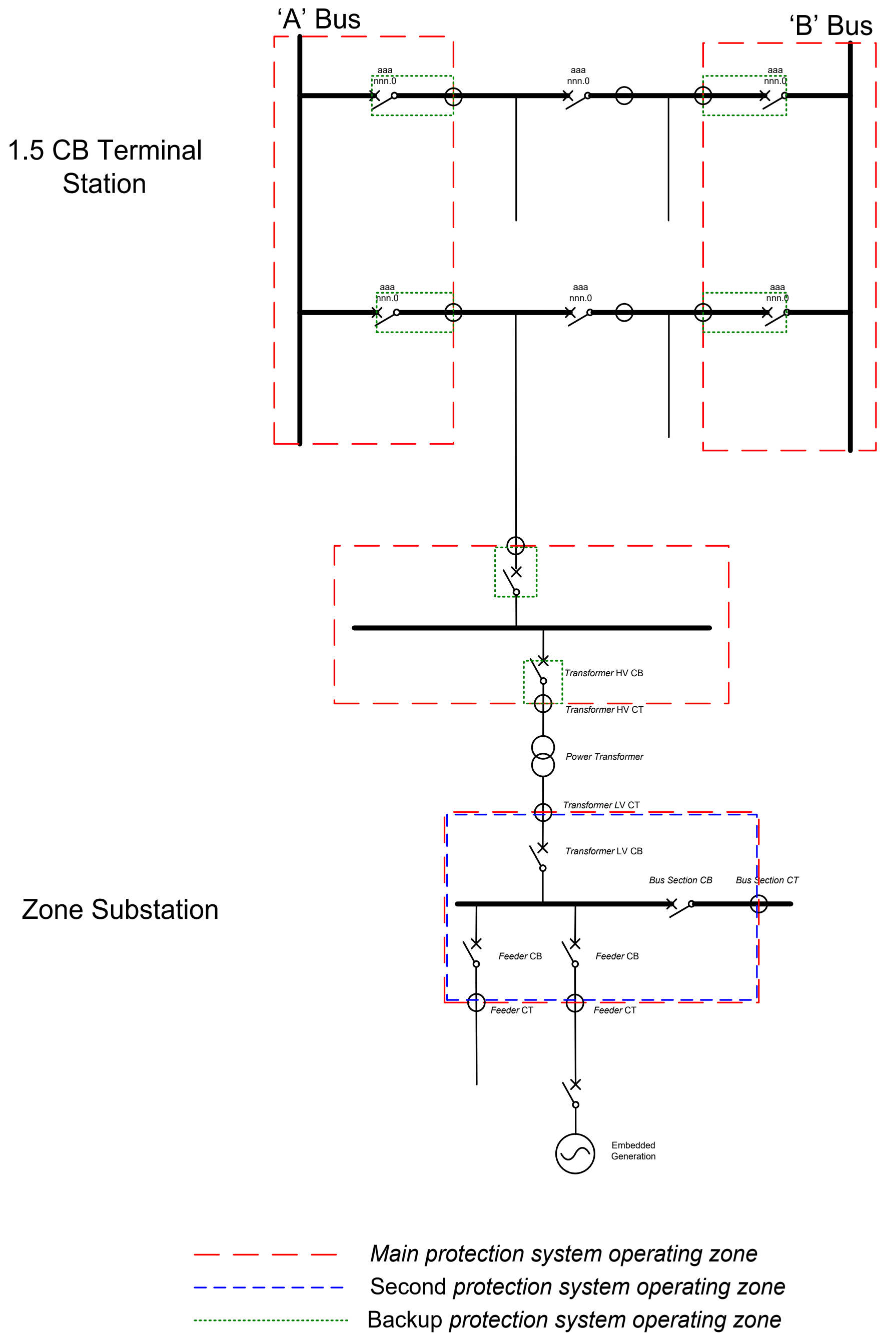
The maximum loop resistance of a CT plus leads for any one CT in the group can be calculated from the following equation:

$$R_{\text{Loop\_Max}} = \frac{1}{1.21615} \cdot \left(\frac{V_{\text{Set}}}{\left(\frac{I_{\text{F\_Max}}}{N}\right)} \right)$$

Where $\frac{1}{1.21615}$ is a factor to convert resistance from Ohms at 75° C to Ohms at 20° C.

4.7 Appendix C – Operating Zones

The following drawing demonstrates the main protection system and the backup protection system operating zones.



4.8 Appendix D – Western Power's Preferred Busbar Protection schemes

4.8.1 330 kV, 220 kV, 132 kV and 66 kV

Main Protection 1	Main Protection 2
a) Current measuring high impedance b) Low impedance (for double bus configuration)	a) Voltage measuring high impedance b) Low impedance (for double bus configuration)

Backup Protection 1	Backup Protection 2
a) Circuit breaker failure	a) Circuit breaker failure

4.8.2 33 kV, 22 kV, 22 kV, 11 kV, 6.6 kV Indoor Busbars

Main Protection system	Second Protection system
a) High Impedance b) Low Impedance	a) Transformer HV IDMT overcurrent

4.8.3 33 kV Outdoor Busbars

Main Protection System	Second Protection system
a) High Impedance b) Low Impedance	a) Transformer HV IDMT overcurrent

4.9 Appendix E – Advantages / Disadvantages

4.9.1 Transmission Main Protection Schemes

4.9.1.1 High Impedance Scheme

1) Advantages of this option include:
   a) Low cost, simple design, proven highly reliable
2) Disadvantages of this option include:
   a) Double busbar configurations require complex check and discrimination scheme components to guard against incorrect operation for faulty disconnector auxiliary contacts.
   b) Lack of oscillography leads to complex site investigations for failure of secondary wiring.

4.9.1.2 Low Impedance Scheme

1) Advantages of this option include:
   a) For double busbar configuration the check and discrimination scheme components can be included in one relay
   b) Disconnector status is wired to the relay. The relay can detect and alarm for faulty disconnector auxiliary contacts
   c) IDMT over current elements can be set to provide the second feeder protection system. Refer to Section 9 – Feeder Protection.
   d) Can be used where the existing CTs have different CT ratios without requiring interposing CTs.
   e) Oscillography available on each connected circuit.
2) Disadvantages of this option include:
   a) Low impedance schemes are more expensive than high impedance schemes
   b) Low impedance scheme designs, settings and commissioning are more complicated than high impedance schemes.

5 LV Switchboard Protection

5.1 Introduction

The purposes of this section are to:

1) Define at a high level the functional requirements for LV switchboard protection in Western Power zone substations
2) Capture information which explains the reasoning behind the busbar protection design and settings

5.2 Scope

This section applies to LV switchboard protection in Western Power zone substations.

5.3 Functional Requirements

The functional requirements for the LV switchboard protection systems are:

1) Detect and clear faults in the operating zone.
2) Detect and clear faults within times specified by the Technical Rules.
3) Coordinate with upstream and downstream protection systems.
4) Provide backup for downstream protection systems.
5) Clear faults within the thermal limits of associated primary equipment, including the power transformer.
6) It is not a purpose of the LV switchboard protection systems to provide overload, over voltage or under voltage protection for circuit breakers, transformers or conductors.

5.4 LV Switchboard Protection

5.4.1 Introduction

Switchboards comprise standard modules which can be arranged in different configurations to suit the design requirements of the site. There are two standard switchboard configurations and a number of non-standard configurations.

5.4.1.1 Standard Switchboard Configurations

Standard switchboards are used at standard Western Power green field zone substations. These switchboards are also installed in brown field sites. There are two types of standard LV switchboard configurations:

1) Type 1 switchboard which includes:
   a) 1 incomer circuit
   b) 1 bus section circuit
   c) 2 Capacitor bank circuits

d) 4 feeder circuits

e) A1 or A5 busbar

2) Type 2 switchboard which includes:

a) 1 incomer circuit

b) 2 bus section circuits

c) 2 capacitor bank circuits

d) 4 feeder circuits

e) A2, A3, A4 busbars

Refer to Section 5.5 for the staging and integration of these switchboards.

5.4.1.2 Non-Standard Switchboard Configurations

Non-standard switchboards are used at non-standard Western Power green field zone substations and brown field sites. Some of the design issues are highlighted in this document. Because the design is non-standard, site specific design issues must be identified and dealt with on a site specific basis. Common non-standard switchboards include:

1) Type 2 switchboard with 4 bus sections

2) Type 1 or type 2 switchboard with increased feeder or bus section rating

5.4.2 Design Requirements

5.4.2.1 Backup Protection

5.4.2.1.1 Existing Brownfield Sites

Table 5.1 summarises the backup arrangement for pre 2013 LV switchboards at brownfield sites.

Table 5.1 – LV switchboard main protection system backup arrangement – pre 2013 switchboards at brownfield sites

Main Protection system	Battery	Second (Backup) Protection system	Battery
Feeder	2	Transformer LV	1
		Second feeder main [40]	1
		Low impedance busbar[40]	1
Capacitor	2	Transformer LV	1
Busbar	1	Transformer HV	2
Bus section	1	Transformer HV	2
Transformer LV	1	Transformer HV	2

[40] Option when transformer LV cannot meet sensitivity requirements

5.4.2.1.2 New Switchboard at Existing Brownfield Sites

summarises the main and second protection systems for new DNP switchboards at brownfield sites. The new switchboard will normally be connected to a new transformer with duplicated LV overcurrent protection. The new switchboard can also be supplied from existing transformers with LV overcurrent protection on battery 1 only.

Table 5.2 – New DNP switchboard at brownfield site

Main Protection system	Battery	Second (Backup) Protection system	Battery
Feeder	2	Transformer LV	1
		Second feeder main[40]	1
Capacitor	2	Transformer LV [41]	1
Busbar	1	Transformer HV	2
Bus section	1	Transformer HV	2
Transformer LV	1, 2 [42]	Transformer HV	1, 2

5.4.2.1.3 Greenfield Sites

Table 5.3 summarises the backup arrangement for IEC 61850 switchboards installed after 2013 at green field sites.

Table 5.3 – LV switchboard main protection system backup arrangement – greenfield sites

Main Protection system	Battery	Second (Backup) Protection system	Battery
Feeder	1	Second feeder main [43]	2
Capacitor	1	Second capacitor main[43]	2
Busbar	1	Transformer LV	2
Bus section	2	Transformer LV	1
Transformer LV	1 & 2	Transformer HV	1 & 2

5.4.2.2 Non-Standard Design Requirements

5.4.2.2.1 Frame Earth Leakage

Frame earth protection schemes provide some busbar protection without the need for separate CT cores required for the differential schemes. Because modern switchboards can accommodate the required CT cores, the frame earth leakage schemes are considered obsolete.

[41] New transformers designs have a relay on battery 1 and a relay on battery 2. The (battery 2) backups up the SEL751A (battery 1) on the feeders and capacitors for battery faults. The SEL487E (battery 1) backups the SEL751 (battery 1) on the feeders and capacitors for relay faults (common mode failure).

[42] HV and LV overcurrent protection duplicated on new transformer only.

[43] Required for IEC61850 designs

When working with frame earth leakage switchboards the switchboard must be insulated from earth except through the frame leakage CT neutral. This means that there must be insulation:

1) Between the switchboard and where it is mounted
2) In the cable terminations. Specifically the cable screen earth

Adding a new switchboard to a site with an existing frame earth switchboard will generally require running a cable between the new switchboard and the existing switchboard. Because there will generally not be a CT core available in the frame earth switchboard, the cable will not be included in a busbar scheme.

5.4.2.2.2 Type 1 Switchboard Installed at Outdoor Switchgear Sites

These standard switchboards are installed at brown field sites at the T1 or T3 positions.

5.4.2.2.2.1 Design Issues

1) A staged CB fail trip is used to clear a busbar fault if a bus section circuit breaker fails to clear the fault. This minimises the chances of blacking out the substation. The first CB fail trip is sent to the closest existing transformer LV circuit breaker. If this fails to clear the fault, a second delayed CB fail trip is sent to the other existing transformer LV circuit breaker. The total fault clearance time must be checked to ensure it meets the Technical Rules requirements

2) Cable protection. A new CT is required on the existing busbar if the existing transformer LV protection system does not meet the Technical Rules total fault clearance time for faults on the cable connecting the new switchboard. The purpose of the CT is to include the cable in the new switchboard busbar protection.

   When the existing busbar is supplied via the new switchboard, a fault on the cable will be cleared by the new switchboard busbar protection.

   When the new switchboard is supplied via the existing busbars, faults on and downstream of the cable will be cleared by the existing transformer LV protection system. Note that adding the new CT to the existing busbar protection makes a cable fault a small zone fault. The transformer LV protection system must therefore meet the Technical Rules CB Fail total fault clearance time.

Refer to Section 5.5.2.1 for the integration of these switchboards.

5.4.2.2.3 Type 2 Switchboard with 4 Bus Sections

These boards are used at brown field sites to connect a new transformer and new switchboard onto existing outdoor busbars. A cable is run from a bus section to an end of the existing outdoor busbars. This switchboard configuration has the following advantages:

1) If the new transformer is out of service, its load can be divided across the existing transformers. This is important when an existing transformer is not rated to carry its load and the new switchboard load.

2) If either of the existing transformers is out of service, its load can be supplied by the new transformer.

5.4.2.2.3.1 Design issues

1) CB Fail. A staged CB fail trip is used to clear a busbar fault if a bus section circuit breaker fails to clear the fault. This minimises the chances of blacking out the substation. The first CB fail trip is sent to the closest existing transformer LV circuit breaker. If this fails to clear the fault, a second delayed CB fail trip is sent to the other existing transformer LV circuit breaker. The total fault clearance time must be checked to ensure it meets the Technical Rules requirements.

2) New CTs are required on the existing busbars if the existing transformer LV protection system does not meet the Technical Rules total fault clearance time for faults on the cable connecting the new switchboard. The purpose of the CTs is to include the cables in the new switchboard busbar protection.

   When the existing busbar is supplied via the new switchboard, a fault on a cable will be cleared by the new switchboard busbar protection.

   When the new switchboard is supplied via an existing busbar, faults on and downstream of the cable will be cleared by the existing transformer LV protection system. Note that adding the new CT to the existing busbar protection makes a cable fault a small zone fault. The transformer LV protection system must therefore meet the Technical Rules CB Fail total fault clearance time.

Refer to Section 5.5.2.2 for the integration of these switchboards.

5.4.2.2.4 Type 1 or 2 Switchboard with Feeder Circuit Rated as Incomer

These switchboards are typically used to supply a customer with a supply exceeding the standard feeder circuit rating.

5.4.2.2.4.1 Design Issues

1) Cable protection. The cable going to the customer is generally considered a feeder. The protection system includes standard IDMT overcurrent protection. The feeder settings must meet the requirements specified in Section 9 – Feeder Protection.

   The cable may be included in the switchboard busbar protection if:

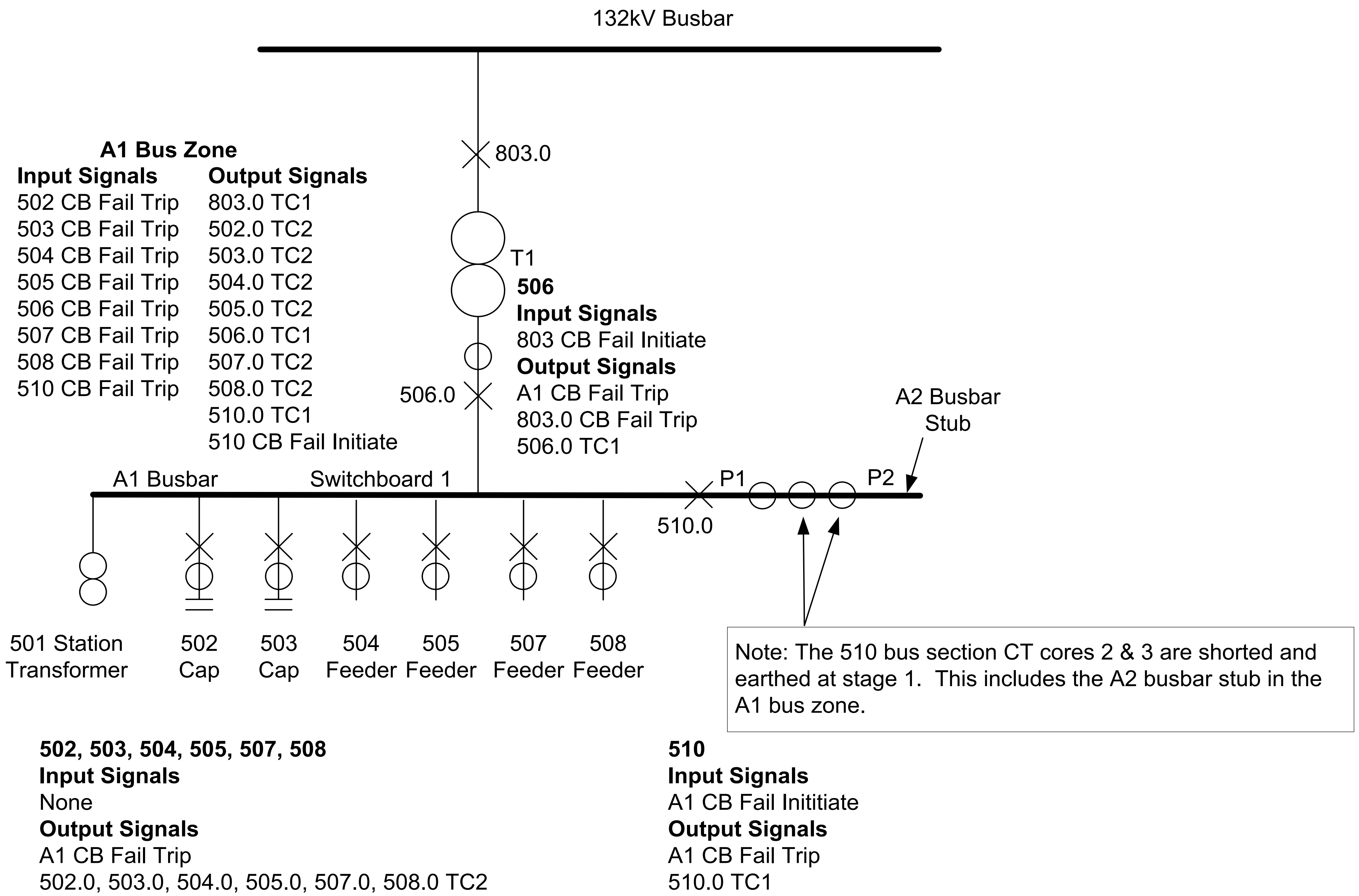
   a) The switchboard is dedicated to a single customer and loss of the entire switchboard is acceptable to the customer

   b) The customer CT is located close enough to the switchboard to allow it to be included in the switchboard busbar protection system

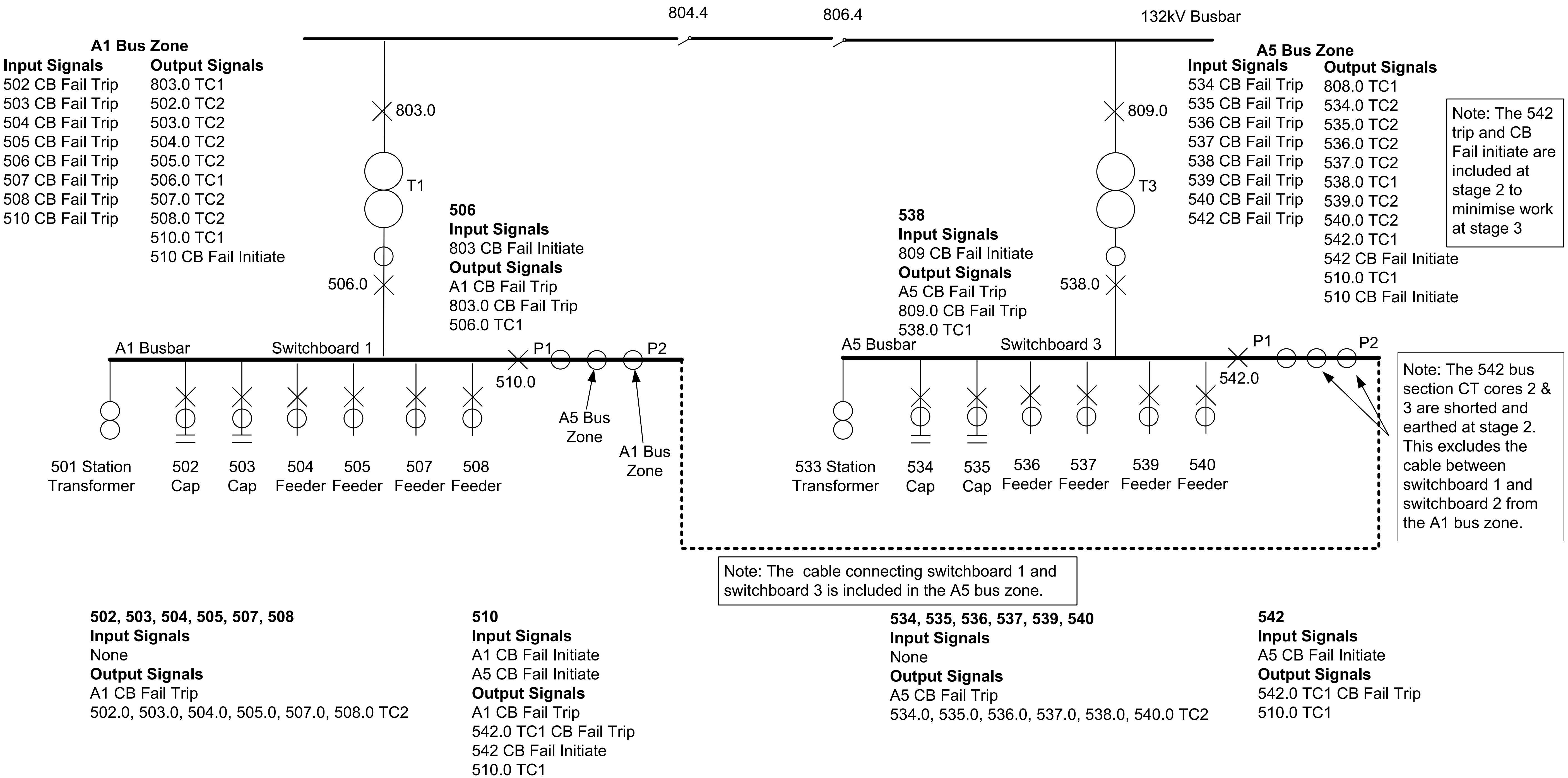
5.5 Appendix A – Protection Overviews

5.5.1 Standard Design

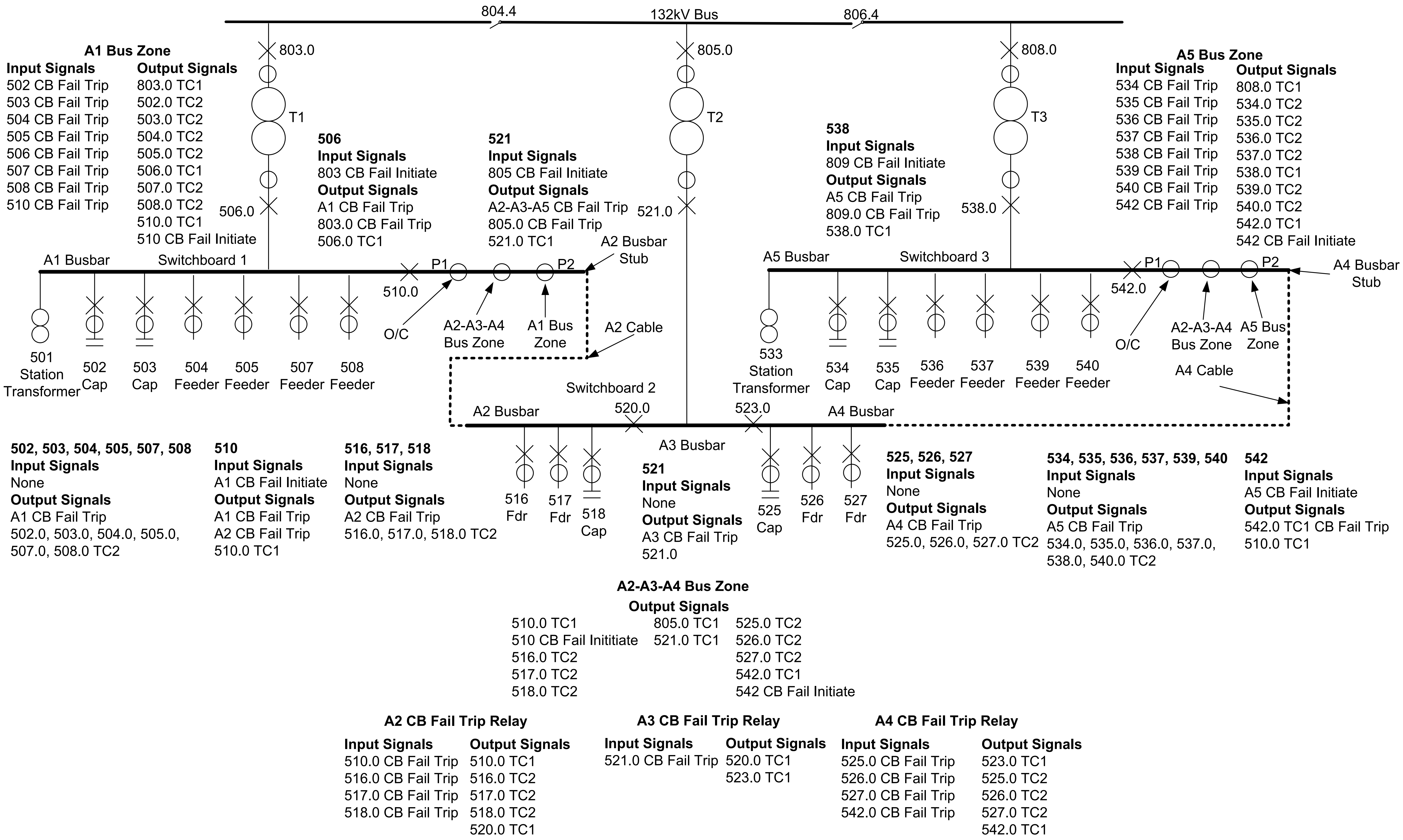
5.5.1.1 Stage 1



5.5.1.2 Stage 2

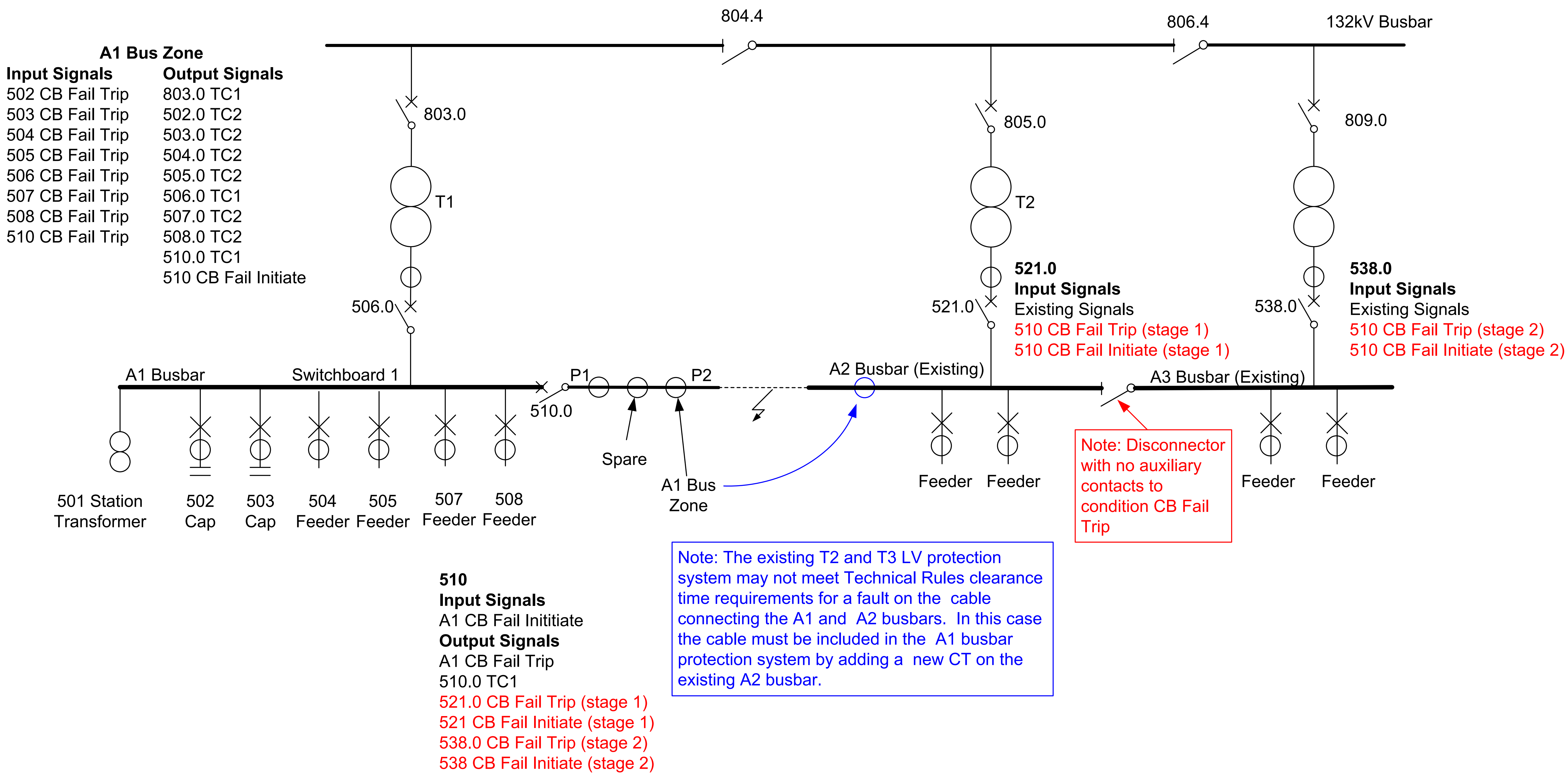

804.4
806.4
132kV Busbar
A1 Bus Zone
Input Signals
502 CB Fail Trip
503 CB Fail Trip
504 CB Fail Trip
505 CB Fail Trip
506 CB Fail Trip
507 CB Fail Trip
508 CB Fail Trip
510 CB Fail Trip
Output Signals
803.0 TC1
502.0 TC2
503.0 TC2
504.0 TC2
505.0 TC2
506.0 TC1
507.0 TC2
508.0 TC2
510.0 TC1
510 CB Fail Initiate
803.0
T1
506
Input Signals
803 CB Fail Initiate
Output Signals
A1 CB Fail Trip
803.0 CB Fail Trip
506.0 TC1
506.0
A1 Busbar
Switchboard 1
P1
P2
510.0
A5 Bus Zone
A1 Bus Zone
501 Station Transformer
502 Cap
503 Cap
504 Feeder
505 Feeder
507 Feeder
508 Feeder
A5 Bus Zone
Input Signals
534 CB Fail Trip
535 CB Fail Trip
536 CB Fail Trip
537 CB Fail Trip
538 CB Fail Trip
539 CB Fail Trip
540 CB Fail Trip
542 CB Fail Trip
Output Signals
808.0 TC1
534.0 TC2
535.0 TC2
536.0 TC2
537.0 TC2
538.0 TC1
539.0 TC2
540.0 TC2
542.0 TC1
542 CB Fail Initiate
510.0 TC1
510 CB Fail Initiate
Note: The 542 trip and CB Fail initiate are included at stage 2 to minimise work at stage 3
809.0
T3
538
Input Signals
809 CB Fail Initiate
Output Signals
A5 CB Fail Trip
809.0 CB Fail Trip
538.0 TC1
538.0
A5 Busbar
Switchboard 3
P1
P2
542.0
533 Station Transformer
534 Cap
535 Cap
536 Feeder
537 Feeder
539 Feeder
540 Feeder
Note: The 542 bus section CT cores 2 & 3 are shorted and earthed at stage 2. This excludes the cable between switchboard 1 and switchboard 2 from the A1 bus zone.
Note: The cable connecting switchboard 1 and switchboard 3 is included in the A5 bus zone.
502, 503, 504, 505, 507, 508
Input Signals
None
Output Signals
A1 CB Fail Trip
502.0, 503.0, 504.0, 505.0, 507.0, 508.0 TC2
510
Input Signals
A1 CB Fail Initiate
A5 CB Fail Initiate
Output Signals
A1 CB Fail Trip
542.0 TC1 CB Fail Trip
542 CB Fail Initiate
510.0 TC1
534, 535, 536, 537, 539, 540
Input Signals
None
Output Signals
A5 CB Fail Trip
534.0, 535.0, 536.0, 537.0, 538.0, 540.0 TC2
542
Input Signals
A5 CB Fail Initiate
Output Signals
542.0 TC1 CB Fail Trip
510.0 TC1

5.5.1.3 Stage 3

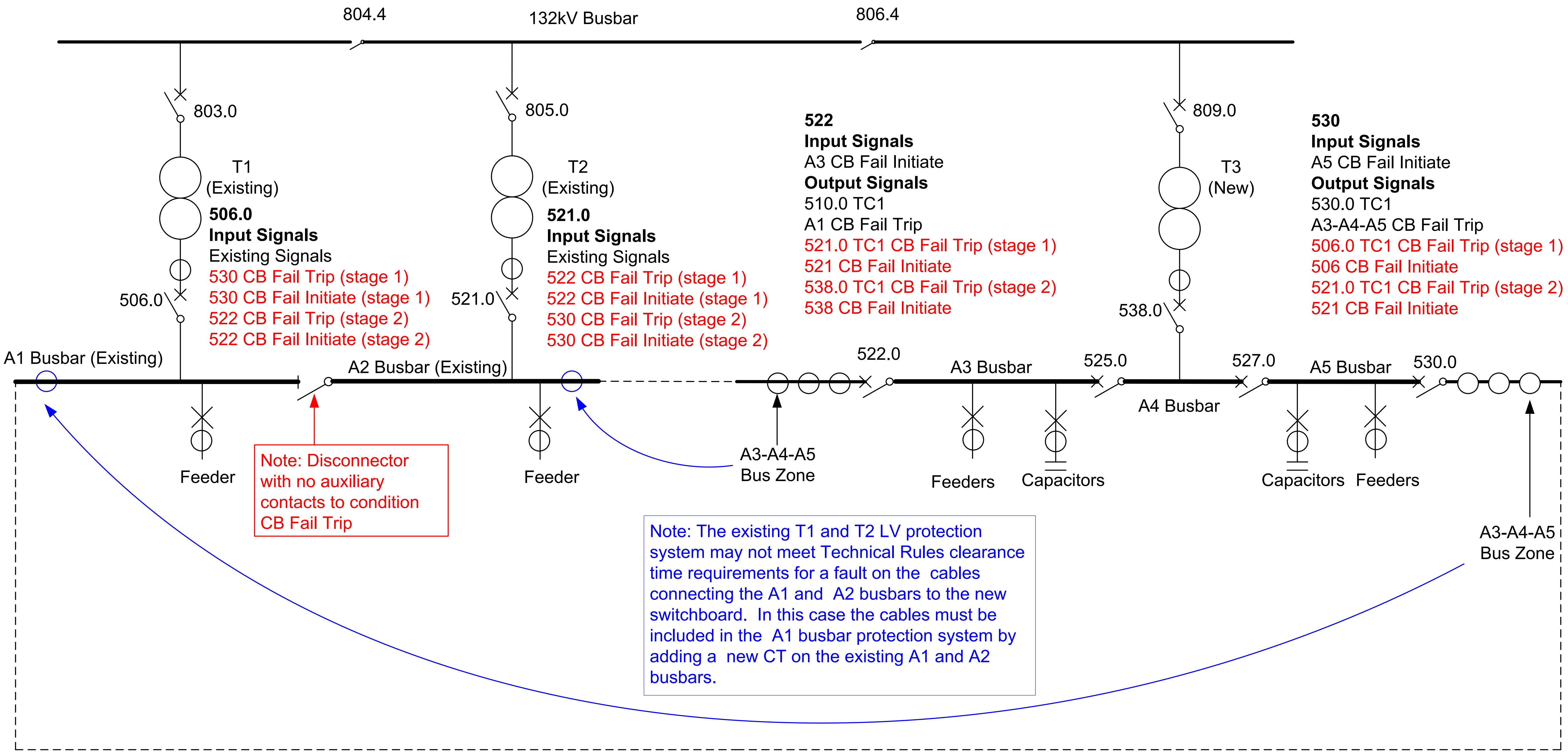

132kV Bus
804.4
806.4
803.0
805.0
808.0
T1
T2
T3
A1 Bus Zone
Input Signals
502 CB Fail Trip
503 CB Fail Trip
504 CB Fail Trip
505 CB Fail Trip
506 CB Fail Trip
507 CB Fail Trip
508 CB Fail Trip
510 CB Fail Trip
Output Signals
803.0 TC1
502.0 TC2
503.0 TC2
504.0 TC2
505.0 TC2
506.0 TC1
507.0 TC2
508.0 TC2
510.0 TC1
510 CB Fail Initiate
506
Input Signals
803 CB Fail Initiate
Output Signals
A1 CB Fail Trip
803.0 CB Fail Trip
506.0 TC1
521
Input Signals
805 CB Fail Initiate
Output Signals
A2-A3-A5 CB Fail Trip
805.0 CB Fail Trip
521.0 TC1
506.0
521.0
A2 Busbar Stub
538
Input Signals
809 CB Fail Initiate
Output Signals
A5 CB Fail Trip
809.0 CB Fail Trip
538.0 TC1
538.0
A5 Bus Zone
Input Signals
534 CB Fail Trip
535 CB Fail Trip
536 CB Fail Trip
537 CB Fail Trip
538 CB Fail Trip
539 CB Fail Trip
540 CB Fail Trip
542 CB Fail Trip
Output Signals
808.0 TC1
534.0 TC2
535.0 TC2
536.0 TC2
537.0 TC2
538.0 TC1
539.0 TC2
540.0 TC2
542.0 TC1
542 CB Fail Initiate
A1 Busbar
Switchboard 1
P1
P2
510.0
O/C
A2-A3-A4 Bus Zone
A1 Bus Zone
A2 Cable
501 Station Transformer
502 Cap
503 Cap
504 Feeder
505 Feeder
507 Feeder
508 Feeder
A5 Busbar
Switchboard 3
P1
P2
542.0
A4 Busbar Stub
O/C
A2-A3-A4 Bus Zone
A5 Bus Zone
A4 Cable
533 Station Transformer
534 Cap
535 Cap
536 Feeder
537 Feeder
539 Feeder
540 Feeder
Switchboard 2
A2 Busbar
520.0
523.0
A4 Busbar
A3 Busbar
516 Fdr
517 Fdr
518 Cap
525 Cap
526 Fdr
527 Fdr
502, 503, 504, 505, 507, 508
Input Signals
None
Output Signals
A1 CB Fail Trip
502.0, 503.0, 504.0, 505.0, 507.0, 508.0 TC2
510
Input Signals
A1 CB Fail Initiate
Output Signals
A1 CB Fail Trip
A2 CB Fail Trip
510.0 TC1
516, 517, 518
Input Signals
None
Output Signals
A2 CB Fail Trip
516.0, 517.0, 518.0 TC2
521
Input Signals
None
Output Signals
A3 CB Fail Trip
521.0
525, 526, 527
Input Signals
None
Output Signals
A4 CB Fail Trip
525.0, 526.0, 527.0 TC2
534, 535, 536, 537, 539, 540
Input Signals
None
Output Signals
A5 CB Fail Trip
534.0, 535.0, 536.0, 537.0, 538.0, 540.0 TC2
542
Input Signals
A5 CB Fail Initiate
Output Signals
542.0 TC1 CB Fail Trip
510.0 TC1
A2-A3-A4 Bus Zone
Output Signals
510.0 TC1
510 CB Fail Inititiate
516.0 TC2
517.0 TC2
518.0 TC2
805.0 TC1
521.0 TC1
525.0 TC2
526.0 TC2
527.0 TC2
542.0 TC1
542 CB Fail Initiate
A2 CB Fail Trip Relay
Input Signals
510.0 CB Fail Trip
516.0 CB Fail Trip
517.0 CB Fail Trip
518.0 CB Fail Trip
Output Signals
510.0 TC1
516.0 TC2
517.0 TC2
518.0 TC2
520.0 TC1
A3 CB Fail Trip Relay
Input Signals
521.0 CB Fail Trip
Output Signals
520.0 TC1
523.0 TC1
A4 CB Fail Trip Relay
Input Signals
525.0 CB Fail Trip
526.0 CB Fail Trip
527.0 CB Fail Trip
542.0 CB Fail Trip
Output Signals
523.0 TC1
525.0 TC2
526.0 TC2
527.0 TC2
542.0 TC1

5.5.2 Non-standard Design

5.5.2.1 Type 1 Switchboard Connected to Existing Busbar



5.5.2.2 Type 2 Switchboard Connected to Existing Busbars



6 Transformer Protection

6.1 Introduction

The purposes of this section are to:

1) Define at a high level the high level functional requirements for transformer protection

2) Capture information which explains the reasoning behind the transformer protection design and settings

6.2 Scope

This section applies to transformer circuits within the Western Power transmission system. Protection of transformers in the distribution system is not covered in this section.

6.3 Functional Requirements

The functional requirements for the transformer protection systems are:

1) Detect and clear faults in the transformer protection operating zone. Refer to Section 6.7.

2) Detect and clear faults within times specified by the Technical Rules.

3) Coordinate with upstream and downstream protection systems.

4) Provide backup for downstream protection systems.

5) Clear faults within the thermal limits of associated primary equipment.

6) The transformer protection system must take into account the following considerations:

    a) Type of upstream and downstream protection systems

    b) Fault levels

    c) Transformer thermal rating

    d) Distribution system fault rating

7) It is not a purpose of the transformer protection systems to provide overload, over voltage or under voltage protection for circuit breakers or conductors.

6.4 Transformer Protection

6.4.1 Introduction

The primary purpose of the transformer protection system is to minimise danger to personnel and loss of supply by clearing faults on the transformer. Other purposes include control and monitoring to facilitate operation of the transformer and to minimise damage to primary equipment.

Current distribution in transformers for various faults can be found in Section 18 – Transformer Sequence Networks and Fault Curren.

6.4.1.1 Terminal Station Transformers

Terminal station transformers are used to transform transmission voltages to other transmission voltages. These are major transmission transformers with:

1. Primary and secondary windings connected to circuits operating at transmission voltages
3. A delta tertiary winding connected to a circuit operating at distribution voltages.

6.4.1.1.1 Voltage Levels

In Western Power's network, terminal station transformers are used to couple the:

2. 330 kV and 132 kV networks
3. 220 kV and 132 kV networks
4. 132 kV and 66 kV networks

Autotransformers are typically used to couple networks where the voltage ratio is less than 3:1.

6.4.1.2 Zone Substation Transformers

Zone substation transformers are used to transform transmission voltages to distribution voltages. A number of different winding configurations are used, depending on where they are utilised in the transmission network.

6.4.1.2.1 Star – Delta with LV Earthing Transformer

The earthing transformers are used to allow LV earth fault currents to flow and to limit their magnitude. There are two types of these transformers:

6.4.1.2.1.1 Single LV Winding

Single LV winding star – delta transformers are typically rated for 33 MVA and are used to transform transmission voltages to distribution voltages. They are used in the South West country areas and metropolitan areas, except the central business district (CBD).

There are two types of earthing transformers (ET):

1) High impedance earthing transformers are used to limit earth fault current to levels of approximately 900 amps at 22 kV. The impedance of the earthing transformer is of the order of 35 ohms / phase.

2) Low impedance earthing transformers limit the earth fault current to levels of approximately 4 – 5 kA at 22 kV. The impedance of the earthing transformer is of the order of 2.5 ohms / phase. Low impedance earthing transformers are used in country zone substations for long feeders with single wire earth return (SWER) loads.

6.4.1.2.1.2 Dual LV windings

Dual LV winding star – delta transformers whose HV winding is typically rated for 60 MVA. They transform 132 kV to 11 kV and are used in the CBD. High impedance earthing transformers are used to limit the earth fault current.

6.4.1.2.2 Star – Delta – Star (HV & LV Solidly Earthed)

These transformers consist of solidly earthed star connected primary and secondary windings and a delta tertiary winding. These transformers have historically been used to couple 132 kV networks with the 66 kV transmission networks in the metropolitan area. In terminal stations the delta tertiary winding is typically 22 kV and is brought out to provide a station supply.

These transformers are also used to step down transmission voltages of 132 kV or 66 kV to distribution voltages of 22 kV or 11 kV in country areas. In zone substations the tertiary winding connections are not brought out from the tank.

6.4.1.2.3 Star – Delta – Star (LV Solidly Earthed)

These transformers consist of a solidly earthed star connected secondary windings and a delta tertiary winding. These transformers are typically used in the zone substations in country areas other than the South West country area. They step down transmission voltages of 132 kV or 66 kV to distribution voltages of 22 kV or 11 kV.

The delta tertiary winding is never loaded and is therefore always solidly earthed.

A solidly earthed neutral on the LV star winding causes LV earth fault currents to be larger than LV phase fault currents (for 3 phase faults). This requires the distribution equipment to be rated to carry the higher earth fault currents. This is acceptable at sites where these transformers are used because of the low earth fault current level.

6.4.1.2.4 Delta – Star

Delta – star transformers have historically been used in zone substations in the metropolitan and South West country areas to transform voltages from 66 kV to voltages of 22 kV, 11 kV or 6.6 kV.

A solidly earthed neutral on the LV star winding causes LV earth fault currents to be larger than LV phase fault currents (for 3 phase faults). This requires the distribution equipment to be rated to carry the higher earth fault currents. This is acceptable at sites where these transformers are used because of the low earth fault current level due to long feeders.

6.4.1.2.5 Star – Star with LV Earthing Transformer

These transformers have been historically used to transform voltages of 132 kV or 66 kV to 33 kV, 22 kV or 6.6 kV. The HV neutral may be solidly earthed depending on site specific requirements.

The LV earthing transformer is used to limit earth fault current magnitude. The earthing transformer also results in a 2:1:1 split in the zero sequence currents in the LV winding. Reducing the fault current to 2/3 reduces stress on the transformer for earth faults to 4/9.

6.4.1.2.6 Earthing Transformers

Earthing transformers are used to:

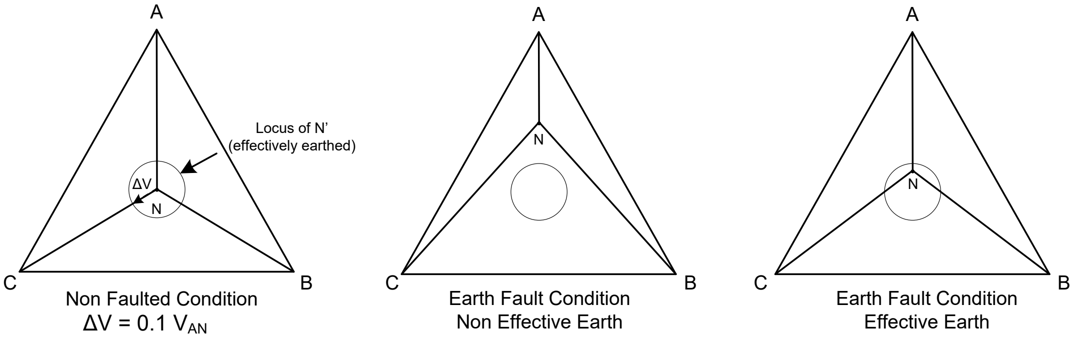
1) Supply zero sequence currents to unearthed star and delta systems. When used in unearthed star system, the fault current in the faulted phase is reduced to 2/3 x $3I_0$ compared to a solidly earthed star. This reduces the mechanical forces to 4/9 compared to a solidly earthed star (i.e. mechanical forces reduced by 55%). Refer to Section 18 – Transformer Sequence Networks and Fault Currents.

2) Regulate earth fault current on the distribution system. Western Power’s standard 22 kV earthing transformer is designed to deliver a nominal 900 A fault current (300 A / phase). Refer to section 6.11.

3) Provide an effectively earthed system. Under normal conditions the phase – neutral voltages of a delta system are balanced. Under earth fault conditions, the neutral point will shift towards the faulted phase. For a system to be effectively earthed the phase – neutral voltage of the healthy phases must remain within 10% of nominal.

4) During earth fault conditions on long rural feeders the impedance of the faulted phase is significant. The magnitude of the neutral shift is the product of the fault current and the zero sequence impedance between the fault and the source. This includes the impedance of the earthing transformer. The zero sequence impedance can cause the neutral point to be shifted by more than 10%. Low impedance earthing transformers reduce the overall zero sequence impedance, keeping the phase – neutral voltage within 10% of nominal under earth fault conditions. Refer to Figure 6.1 below.

Figure 6.1 – Neutral point shifted under fault conditions



6.4.2 Design Requirements

Section 6.5 outlines the design requirements for standard functions.

6.4.2.1 Main Protection System

The operating zone of the main protection system is defined by the current transformers on each winding. Each main protection scheme must be able to protect the transformer with the other main protection scheme out of service. Alarms should be brought back via the alternate protection scheme.

Table 6.1 and Table 6.2 summarise the functions required for each of the main protections schemes at green field sites. The requirements for brownfield applications are outlined in section 6.8.

Table 6.1 – Green field terminal station transformer main protection schemes

Main Protection Scheme 1	Main Protection Scheme 2
Biased Differential	Biased Differential
Instantaneous Differential	Instantaneous Differential
HV IDMT Overcurrent	HV IDMT Overcurrent
LV IDMT Overcurrent	LV IDMT Overcurrent

TV IDMT Overcurrent [44]	TV IDMT Overcurrent [44]
HV Instantaneous Overcurrent	HV Instantaneous Overcurrent
LV Instantaneous Overcurrent	LV Instantaneous Overcurrent
TV Instantaneous Overcurrent [44]	TV Instantaneous Overcurrent [44]
Combined HV/LV REF [45]	Combined HV/LV REF [45]
TV (Restricted) Earth Fault [44]	TV (Restricted) Earth Fault [44]
Earthing Transformer REF [46]	
HV REF [47]	HV REF [47]
LV REF [47]	LV REF [47]
TV Standby Earth Fault [44]	TV Standby Earth Fault [44]
Buchholz	Main Tank Pressure
Tap Changer Pressure	Oil Temperature
HV Winding Temperature	LV Winding Temperature
Earthing Transformer Pressure [46]	TV Winding Temperature

Table 6.2 – Green field zone substation transformer main protection schemes

Main Protection Scheme 1	Main Protection Scheme 2
Biased Differential	Biased Differential
Instantaneous Differential	Instantaneous Differential
HV IDMT Overcurrent	HV IDMT Overcurrent
HV Instantaneous Overcurrent	HV Instantaneous Overcurrent
LV IDMT Overcurrent	LV IDMT Overcurrent
LV IDMT Earth Fault	LV IDMT Earth Fault
LV Standby Earth Fault	LV Standby Earth Fault
TV IDMT Earth Fault [48]	
HV Restricted Earth Fault	HV Restricted Earth Fault

[44] Required when the transformer has a loaded tertiary
[45] Required for autotransformers only
[46] Required when an autotransformer has an earthing transformer (ET) on the tertiary winding
[47] Required for non-autotransformers
[48] Required when the transformer has a loaded tertiary

LV Restricted Earth Fault	LV Restricted Earth Fault
TV Restricted Earth Fault [48]	
Buchholz	Main Tank Pressure
Tap Changer Buchholz	
Earthing Transformer Pressure [49]	Oil Temperature

6.4.2.2 Backup Protection System

Western Power's preference is for duplicated circuit breaker failure schemes at all transmission voltages to:

1) To meet local total fault clearance time requirement
2) Allow the system to be reconfigured in the future without affecting the backup protection system
3) Minimise risk of blacking out a terminal station for a remote backup operation

6.4.2.3 Residual Current

Residual current measurement of the phase CTs using a separate element in the protection relay is required. The reason for this requirement is so the actual system imbalance is measured by the protection element.

6.4.2.4 Relay Reset Requirements

A transformer protection device that trips for transformer faults shall:

1) Latch
2) Retain its state when powered down.

A transformer protection device that trips for system faults must be self resetting.

6.4.2.5 Tertiary Winding

Protection on the tertiary delta winding is only required if the winding connections are brought out from the tank. The tertiary winding provides flux equalization and connection to the zero sequence bus. It may also be used to provide station supplies or connection of reactive power compensation.

The core and tank of a transformer are earthed. If the tertiary winding is not earthed, vibration of the tertiary winding insulation can cause a build up of static electricity resulting in a flashover. To keep the tertiary winding and core at the same potential and prevent a flashover the tertiary winding must be earthed. The earth connection can be provided by:

1) If an external circuit is connected to the tertiary winding the external circuit will provide the earth connection.
2) When the tertiary winding connections are not brought out from the tank the earth must be connected above the neutral of the CT on the highest voltage winding providing restricted earth fault protection. This provides protection for earth faults on the tertiary winding by the restricted earth fault protection.

[49] Required when the transformer has an LV earthing transformer (ET)

The tertiary winding may be supplied with a link. Removing this link opens the delta and removes the tertiary winding zero sequence impedance from the sequence network. This reduces the zero sequence currents on the LV winding.

6.4.2.5.1 Tank Delta

In addition to the tertiary winding, zero sequence flux also flows between the core and the transformer tank. This effectively forms a tank delta zero sequence impedance which is in parallel with the tertiary winding zero sequence impedance. The tank delta zero sequence impedance is typically 75% to 300% on the transformer rating (e.g. 7.5 per unit to 30 per unit on for a 10 MVA transformer). Because of the tank delta, zero sequence currents can flow in the LV winding even when a tertiary winding is not present.

6.4.2.6 Effective Restricted Earth Fault

Restricted earth fault is a form of unit protection. A similar degree of protection can be provided in a non-unit form termed 'effective restricted earth fault protection'. A set of residually connected CTs is required to provide transformer HV restricted earth fault protection on the following transformers:

1) HV neutral not earthed
2) HV delta winding

With no earth connection on the winding, earth fault current can only be present if there is an earth fault on the winding. The earth fault protection is therefore restricted to the HV winding.

6.4.2.7 Control

Grid Transformation Planning Engineers are responsible for determining appropriate automatic voltage regulation (AVR) settings. The AVR operation time delay is typically different between Terminal Station and Zone Substation transformers, to ensure appropriate AVR coordination and network voltage management.

6.4.2.7.1 Zone Substation Transformers

A typical AVR operation time delay setting for Zone Substation Transformers is 60 s.

6.4.2.7.2 Transmission System Transformers

A typical transmission AVR time delay setting is 40 s. It is important that the transmission transformer AVR time delay is less than the distribution transformer time delay. This allows a single terminal station transformer to regulate a voltage excursion on the transmission system rather than multiple zone substation transformers changing taps.

6.4.3 Main Protection System Standard Functions

Standard functions are provided on all transformer circuits to assist with standardisation of protection design and setting files.

6.4.3.1 Biased Differential

The purpose of biased differential is to detect and clear internal faults within the operating zone while remaining stable for external faults. Biased differential is a form of unit protection and is standard on all transformers connected to the transmission system. This ensures that the Technical Rules total fault clearance times can be met in all situations.

Biased differential protection is inherently insensitive in order to allow for:

1) Tap changing
2) Zero-sequence currents in the transformer windings do not sum to zero they have to be eliminated in order for electromechanical differential scheme to balance.

Bias differential schemes are therefore at best insensitive to earth faults.

6.4.3.1.1 Differential Characteristic

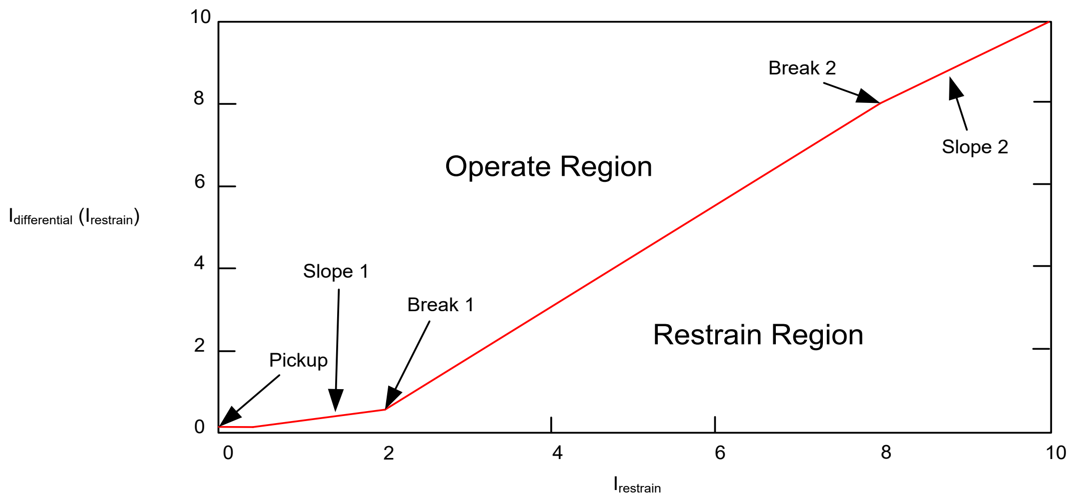
The purpose of the differential characteristic is to define the ratios of differential current to restraint current that will cause the relay to operate or restrain. The differential characteristic is based on differential restraint ratios for the transformer winding currents during various current flow conditions such as no load, normal operation and through faults.

During normal operation of the transformer, which can include external faults, apparent differential current can arise for the following reasons:

1) CT error current due to errors and saturation
2) Matching error current due to tap changer movement away from the principal tap
3) Magnetisation current
4) Inrush current

The differential characteristic settings can be used to configure the differential characteristic as required and as shown in Figure 6.2.

Figure 6.2 – Typical differential characteristic settings [50]



The protection design engineer can control the shape of the differential characteristic by choosing settings for pickup, slopes 1 & 2 and breaks 1 & 2.

The settings are selected to meet the following requirements:

[50] Siemens PTD EA – Applications for SIPROTEC Protection Relays 2005 Fig 8

1) Pickup: This setting provides restraint at very low load, or very low through fault conditions against apparent differential current caused by:

   a) Magnetisation current of the protected transformer.

   b) Steady state CT errors.

   c) Tap changer movement away from the principal tap position.

   A setting of 0.20 per unit has been used in the past with success.

2) Slope 1: This setting determines the slope of the characteristic between the points at which slope 1 intersects the pickup and break 1. This section of the characteristic is intended to provide differential restraint during normal operating conditions. This includes the absence of close by faults or events causing CT saturation. The setting provides restraint against differential current caused by:

   a) Magnetisation current of the protected transformer.

   b) Steady state CT errors.

   c) Tap changer movement away from the principal tap position.

   d) Low, but offset fault currents arising from out of zone faults.

   The setting must allow detection of minimum internal faults.

   A slope based on twice the worst apparent differential current arising from tap changer movement has been used successfully in the past.

3) Break 1: The settings for break 1 and break 2 depend on the capability of CTs to correctly transform primary currents into secondary currents during external faults. The setting for break 1 is based on the maximum load current of the transformer. Any differential current greater than the full load current must be due to something other than tap changer movement. Break 1 is the point at which the relay calculates and introduces further restraint as part of the differential characteristic.

4) Break 2: During through fault conditions, the CTs will begin to saturate due to AC components alone. The setting for break 2 corresponds to the current at which the CT with the lowest knee point begins to saturate.

5) Slope 2: This setting determines the slope of the differential characteristic above break 2. This section of the differential characteristic provides restraint during heavy through fault conditions, where CT saturation results in high differential current. Slope 2 should be set to cater for the worst case where one set of CTs saturates but the other set does not. In such a case the ratio of the differential current to restraint current can be as high as 95% to 98%.

6.4.3.2 Inrush Inhibit

The purpose of inrush inhibit is to restrain the bias differential function during inrush conditions. The traditional method on providing restraint against magnetising inrush current is based on second harmonics. Restraint is provided when the ratio of the second harmonic to the fundamental component of the inrush current exceeds the inrush inhibit level setting. The setting must be exceeded on 2 of the 3 phases of the HV contribution to the differential relay. A setting of 15% to 20% (depending on the relay used) has been used successfully in the past.

Cross blocking, which allows the second harmonic in any one phase to be used as a restraint quantity in any other phase, is always used.

Inrush inhibit is a standard function in all transformer main protection system relays that provide biased differential protection.

6.4.3.3 Over Excitation Inhibit

The purpose of over excitation inhibit is to restrain the bias differential function during over fluxing conditions. During over fluxing conditions fifth harmonics would otherwise cause the differential function to operate. Blocking is done on a per phase basis. The blocking will be effective for the entire length of time that sufficient 5th harmonics are present to cause the blocking to assert. It is reasonable to enable the function if:

1) The application includes over fluxing protection, or
2) The transformer is not likely to be subjected to over excitation which may be caused by load rejection, or
3) The transformer is not fed via long radial line which is possibly subject to the Ferranti effect

A setting of 30% has been used successfully in the past.

Over excitation inhibit is a standard function in all transformer main protection relays that provide bias differential protection.

6.4.3.4 Instantaneous Differential

The purpose of instantaneous differential is to detect and clear faults on the transformer HV bushings and associated winding ends. This function responds to differential current and does not have any bias or harmonic restraint. It therefore operates faster than the differential element. Instantaneous differential is standard on all transformers.

The pickup settings are selected to meet the following requirements:

1) Lower limit:
    a) It is standard practice to set elements to 1.3 x maximum fault level at the LV busbar. This setting provides as much protection for the transformer windings as possible, while not responding to LV busbar faults. The 1.3 x factor allows for off nominal tap positions of the transformer, errors in the relay, CT errors, plus a safety margin.
2) Upper limit: The upper limit is calculated from:
    a) Allowance for relay errors.
    b) Sensitive enough to detect all faults on the HV Post CTs and HV transformer bushings
3) If the lower limit exceeds, the upper limit the following procedure is followed:
    a) The lower limit LV busbar fault level is based on the minimum HV plant fault rating
    b) The lower limit pickup can be made large enough to avoid operation for:
        i) Inrush. Inrush current depends on several factors, including point of wave of switching, remnant core flux and source impedance.
        ii) Through fault conditions. Allowance for through fault conditions involves considerations such as fault levels, CT saturation and tap changer movement away from the principal tap.

Saturation of one set of CTs (HV, or LV) is highly unlikely. The 1.3 factor used in the lower limit calculation can be decreased however impact on security must be examined.

These constraints limit the operating zone to the transformer HV bushings and associated winding ends.

If the lower limit still exceeds the upper, then an alternative form of protection must be considered.

6.4.3.5 Inverse Definite Minimum Time Overcurrent

The purpose of inverse definite minimum time (IDMT) overcurrent is to detect and clear 3 phase faults. IDMT overcurrent may also respond to faults involving heavy unbalance and/or earth faults.

IDMT overcurrent functions are provided as a standard function on all transformers.

6.4.3.5.1 Autotransformers

For a 3 winding autotransformer is it beneficial to provide each winding with IDMT overcurrent protection. In general, such protection will be set to satisfy the following objectives:

1) Allow continuous operation of the associated winding at its long time emergency rating (LTER).
2) Provide backup for the faster transformer protective functions such as biased differential, restricted earth fault and instantaneous overcurrent for faults within the transformer.
3) Provide as much backup protection for external faults as possible. Because the lower limit of the pickup is the LTER of the winding, backup for external faults is usually not possible.
4) Provide adequate thermal protection for the associated winding in the range of current between the winding LTER and the maximum expected through fault current.
5) Coordinate with adjacent time delayed protection.

Objectives 1, 2 and 3 influence the choice of pickup, but will conflict if the minimum fault levels are less than the LTER. Objectives 4 & 5 influence the choice of time multiplier setting, but will conflict if the thermal withstand time of the winding at the maximum through fault level is less than the operating time of adjacent time delayed protection.

6.4.3.5.1.1 HV IDMT Overcurrent

The settings are selected to meet the following requirements:

1) Pickups determined by the following:
   a) Lower Limit: The lower limit is calculated from:
      i) The LTER of the HV winding. This may result in a pickup that will not detect faults on the tertiary winding. It will therefore not provide backup for the bias differential function for internal faults or other functions for external faults. If the only load on the tertiary supply is the earthing transformer, the pickup can be based on the sum of the LTER of the earthing transformer and LV winding. While faults on the tertiary may still not be detected, this will provide better sensitivity.
      ii) Allowance for relay errors.
      iii) CT errors are small and complex. Upper limit: Must meet Western Power’s sensitivity requirements.

2) The time multiplier setting (TMS) must:
   a) Coordinate with associated time delayed protection such as CB failure and zone 2 clearance times
   b) Detect and clear a bolted three phase fault between the LV winding and LV bushing CTs within the thermal limits of the HV winding.

   A setting of 70% of the thermal withstand time of the HV winding has been used successfully in the past.

6.4.3.5.1.2 LV IDMT Overcurrent

The settings are selected to meet the following requirements:

1) Pickups determined by the following:
   a) Lower Limit: The lower limit is calculated from:
      i) The LTER of the LV winding. This will result in a pickup that will not detect faults on the tertiary winding. It will therefore not provide backup for the bias differential function for internal faults or other functions for external faults.
      ii) Allowance for relay errors.
      iii) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements.
2) The time multiplier setting (TMS) must:
   a) Coordinate with associated time delayed protection such as CB failure and zone 2 clearance times
   b) Clear a bolted three phase fault between the HV winding and HV bushing CTs within the thermal limits of the LV winding.

   A setting of 70% of the thermal withstand time of the LV winding has been used successfully in the past.

6.4.3.5.1.3 TV IDMT Overcurrent

The settings are selected to meet the following requirements:

1) Pickups determined by the following:
   a) Lower Limit: The lower limit is calculated from:
      i) The LTER of the TV winding. If the only load on the tertiary is the station supply, then the pickup can be based on the LTER of the earthing transformer. This pickup will detect all relevant faults on the tertiary and 440 V systems.
      ii) Allowance for relay errors.
      iii) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements.
2) The time multiplier setting (TMS) must:
   a) Clear a bolted three phase fault between the 440 V winding of the earthing transformer and the 440 V fuses within the thermal limits of the earthing transformer.

6.4.3.5.2 Zone substation Transformers

6.4.3.5.2.1 LV IDMT Overcurrent

When LV IDMT overcurrent can provide the feeder second protection system, the operating zone extends from the transformer LV CT to the first feeder recloser. When the LV IDMT overcurrent does not provide the feeder second protection system, the operating zone extends to the busbar CTs.

LV IDMT overcurrent is a standard function on all zone substation transformers. The settings are selected to meet the following requirements:

1) Pickup determined by the following:
    a) Lower Limit: The lower limit is calculated from:
        i) The minimum of the LTER of the transformer or rating of Primary Equipment associated with the transformer.
        ii) Allowance for relay errors.
        iii) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements.
2) The time multiplier setting (TMS) must:
    a) Allow the slowest LV protection systems to grade with the transformer protection systems
    b) Allow the HV and LV IDMT overcurrent functions to clear a bolted three phase fault on the LV busbar without exceeding the thermal limits of the transformer.

6.4.3.5.2.2 HV IDMT Overcurrent

The HV and LV IDMT overcurrent elements are set without deliberately providing a grading step across the transformer. This allows the short term load rating of the transformer to be carried without tripping. The short term rating can be up to 150% of the continuous rating of the transformer.

HV IDMT overcurrent is a standard function in all main protection 2 relays.

6.4.3.5.2.3 TV IDMT Overcurrent

TV IDMT overcurrent is a standard function on transformers with loaded tertiary windings. It is supplied from the tertiary winding bushing CTs.

The settings are selected to meet the following requirements:

1) Pickups determined by the following:
    a) Lower Limit: The lower limit is calculated from:
        i) The minimum of the LTER of the tertiary winding or rating of Primary Equipment associated with the transformer.
        ii) Allowance for relay errors.
        iii) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements.
2) The time multiplier setting (TMS) must:

a) Allow the slowest TV protection systems to grade

b) Allow the TV IDMT overcurrent functions to clear a bolted three phase fault on the TV bushing without exceeding the thermal limits of the TV winding.

6.4.3.6 HV Instantaneous Overcurrent

The purpose of HV instantaneous overcurrent is to quickly detect and clear faults on the associated bushings and windings.

Instantaneous overcurrent is standard function for all windings on all transformers.

The instantaneous overcurrent function pickups are set to 1.3 x the maximum through fault current.The factor of 1.3 prevents operation for faults on associated busbars.

6.4.3.7 Transformer LV Paralleling Overcurrent

Transformer paralleling overcurrent is provided on the LV of zone substation transformers. The purpose of the transformer paralleling overcurrent (TPO) function is to allow paralleling of transformers without damaging distribution equipment. When transformers are operated in parallel the fault level may exceed the rating of the distribution equipment. The two types of TPO functions are the:

1) Feeder TPO function which has no deliberate time delay. A loss of discrimination with downstream reclosers is considered to be acceptable when transformers are paralleled. The feeder TPO function is comprised of an independent instantaneous overcurrent element. The feeder TPO is provided by the feeder main protection system.

2) Transformer TPO function is time delayed by 150 ms to allow the feeder TPO to operate first for feeder faults. The transformer TPO element is comprised of an independent definite time overcurrent element.

6.4.3.7.1 Standard Settings

1) Transformer. At 22 kV the standard feeder setting of 3 kA is divided equally between two parallel transformers resulting in a standard pickup setting of 1.5 kA.

Transformer TPO a standard function in all zone substation main protection 1 relays.

6.4.3.8 Earth Fault

The purpose of earth fault protection is to detect and clear faults involving earth.

6.4.3.8.1 Restricted Earth Fault

Restricted earth fault (REF) for all windings is a standard function in main protection 1 relays.

REF schemes detect and clear faults on a single winding (i.e. HV, LV or TV). REF schemes are therefore impervious to tap changing and can be set very sensitive to detect earth faults.

Earth faults are the most common fault on transformers. The construction of a transformer is such that the incoming conductors and the windings of each phase are surrounded by earthed objects (the core and tank). When the HV and LV current transformers are external to the tank, the bushings, core and tank are within the REF zone of operation. The restricted earth fault zone of operation depends on the type of winding and its earthing. Table 6.3 below describes these operating zones. Refer to Section 6.12.

Table 6.3 – Restricted earth fault operating zones

Winding Type	Operating zone
Autotransformer combined HV/LV restricted earth fault	The operating zone is defined by the HV winding phase CTs, LV winding phase CTs and autotransformer neutral CT
Autotransformer earthing transformer restricted earth fault	The operating zone is defined by the delta winding phase CTs and the earthing transformer neutral CT
Star winding with a solid earth	The operating zone is defined by the neutral phase CTs and the star winding CT
Delta or unearthed star winding with an earthing transformer	The operating zone is defined by the earthing transformer neutral CT and the delta or star winding CTs
Unearthed HV delta or star winding	The operating zone is defined by the unearthed HV winding and the phase CTs

Combined HV / LV restricted earth fault and earthing transformer restricted earth fault are provided as standard functions on all auto transformers.

HV restricted earth fault and LV restricted earth fault are provided as standard functions on all zone substation transformers.

The settings are selected to meet the following requirements:

1) Pickups determined by the following:
    a) Lower Limit: The lower limit is calculated from:
        i) Must be stable for through faults
        ii) Allowance for relay errors.
        iii) CT errors are small and complex. Upper limit: Must meet Western Power’s sensitivity requirements.

6.4.3.8.2 Standby Earth Fault

Standby earth fault (SBEF) provides LV system backup protection. The standby earth fault CT is located on the single earth connection to the circuit it is protecting. This could be:

1) The neutral of an earthing transformer connected to:
    a) The tertiary of an autotransformer
    b) The LV of star – delta transformers
    c) The LV of star – star transformer (LV unearthed)
2) The solidly earthed neutral of an LV star winding

The standby earth fault operating zone is therefore the associated star or delta winding and downstream circuits. For the case of an earthing transformer, SBEF will provide protection for earth faults within the earthing transformer.

6.4.3.8.2.1 Autotransformer

TV standby earth fault is provided as a standard protection 2 function on the autotransformer tertiary winding. When the only load on the tertiary winding is the station supply the following standard settings are applied:

1) Pickup = 0.1 per unit

2) TM = 0.05

6.4.3.8.2.2 Zone substation

LV standby earth fault is provided as a standard function on all zone substation transformers.

1) When the standby earth fault CT is on the neutral of a high impedance earthing transformer the following settings apply:

   a) Pickup = 90 amps

   b) TM = 1.00

   This standard setting has sufficient margin with downstream protection to allow relay and CT errors to be neglected.

2) When the standby earth fault CT is on the neutral of a low impedance earthing transformer the settings are site specific. The low impedance earthing transformers are typically used at country sites with SWER loads. The settings are chosen to protect the thermal rating of the power transformer and meet Western Power's sensitivity requirements.

6.4.3.8.3 LV IDMT Earth Fault

When LV IDMT earth fault provides the feeder second protection system the operating zone extends from the transformer LV CT to the first feeder recloser. When the LV IDMT overcurrent does not provide the feeder second protection system the operating zone extends to the busbar CTs.

LV IDMT earth fault is a standard function in all zone substation main protection relays.

The following settings are standard on metropolitan zone substation transformers:

1) Pickup = 72 amps

2) TM = 0.80

Settings for country transformers, which often have solidly earthed neutrals, are site specific and are selected to meet the following requirements:

1) Pickup determined by the following:

   a) Lower Limit: The lower limit is calculated from:

      i) The pickup must be greater than the down stream protection pickups

      ii) Allowance for relay errors.

      iii) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements.

2) The time multiplier setting (TMS) must:

a) Allow the slowest downstream LV protection system to grade with the transformer protection systems

b) Allow LV IDMT earth fault function to clear a bolted single phase fault without exceeding the thermal limits of the transformer.

6.4.3.9 Negative Phase Sequence

The purpose of negative phase sequence (NPS) is to detect and clear unbalanced fault conditions which do not necessarily involve earth. The NPS elements do not respond to balanced load so they can be set more sensitively than overcurrent elements.

Negative phase sequence is a standard function in all main protection relays.

The NPS function is a combination of an inverse curve and a definite time (DT) function. The definite time function is set to 2.4 seconds which is therefore the fastest the transformer NPS will clear a fault. The 2.4 second operating time allows the feeder NPS to operate first.

The settings are selected to meet the following requirements:

1) The inverse time and definite time pickups are determined by the following limits:

   a) Lower limit: The lower limit is calculated from:

      i) If all the feeders are provided with the NPS then the pickup of the transformer NPS must not pickup before any feeder NPS picks up. If any feeder is not provided with NPS, then the transformer NPS must not pickup before the slowest feeder phase IDMT overcurrent element.

      ii) The transformer NPS must not pick up for any summated unbalance currents amongst the feeders normally fed from the busbar. Such imbalance may be due to a lack of transposition on the feeder or insulator leakage current.

      iii) Allowance for relay errors.

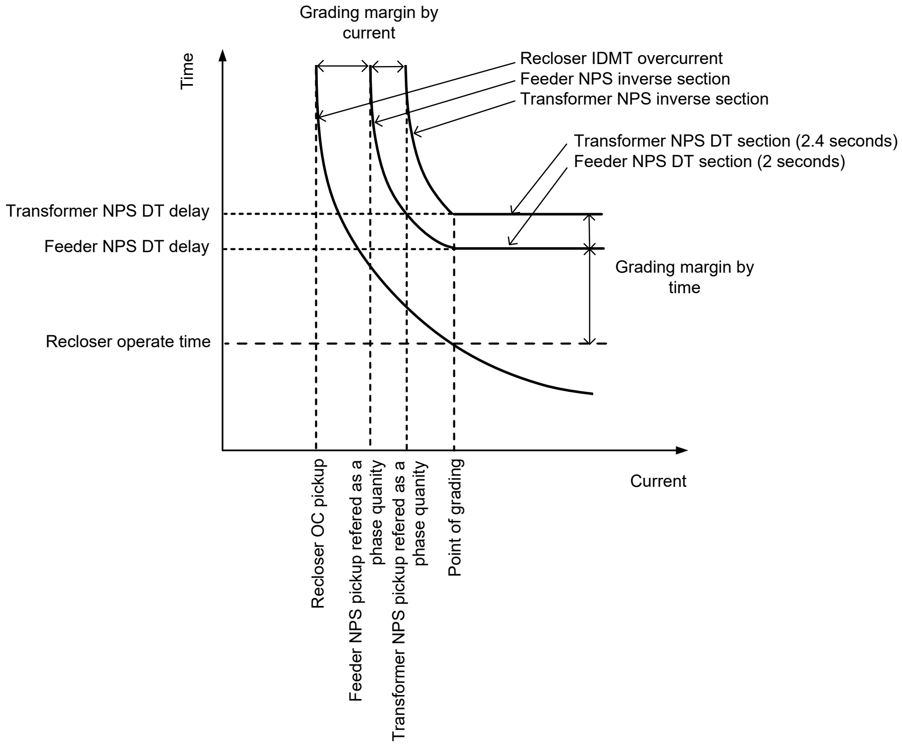
      iv) CT errors are small and complex. Upper limit: Must meet Western Power’s sensitivity requirements.

2) The transformer NPS function must grade with the feeder NPS function at the point where the NPS definite time section intersects with the NPS inverse curve section. This assures grading between the two characteristics at all fault levels. The definite time delay of the curves must therefore be specified before computing the time multiplier of the inverse part of the curve. The standard definite time delays are:

   a) 2 seconds for the feeder

   b) 2.4 seconds for the transformer

Figure 6.3 – Negative Phase Sequence Grading



6.4.3.10 LV Switch On To Fault

The purpose of switch on to fault (SOTF) is to clear fault current caused by closing the associated circuit breaker onto a set of working earths. The working earths would normally be applied to or very near the busbar.

Switch on to fault is a standard function in all transformer LV main protection relays.

SOTF comprises a single phase instantaneous overcurrent element and associated logic. SOTF can be summarised as follows:

1) The SOTF function shall be “armed” when the circuit breaker has been opened and the standard SOTF enable time of 60 seconds has elapsed. The circuit breaker is determined to be open when:

    a) Current is below a set level in all phases and

    b) The circuit breaker auxiliary contacts indicate that the circuit breaker is open

2) The SOTF function shall be "disarmed" when the circuit breaker has been closed and the standard SOTF duration time of 0.6 seconds has elapsed. The circuit breaker is determined to be closed when:

    a) Current is above a set level in at least one phase or

    b) The circuit breaker auxiliary contacts indicate that the circuit breaker is closed

3) SOTF shall be voltage restrained unless a VT is not available. Restraint for load inrush conditions and VT failure is provided by a voltage element. Restraint for VT failure is provided by logic.

6.4.3.10.1 SOTF Settings

The SOTF settings are selected to meet the following requirements:

1) Pickups are determined by the following limits:
    a) The lower limit of the setting is calculated from:
        i) 1.5 x transformer LTER. This allows for motor starting currents, inrush and charging currents following outage of a long feeder.
        ii) A margin. The SOTF margin ensures that the pickup of SOTF is above the maximum intended steady state load. This avoids the sequential event buffer being filled with uninteresting changes.
        iii) Relay errors.

        In practice, a small setting may be acceptable if a very secure restraint for cold load inrush and VT failure conditions is possible [51].
    b) Upper limit: Must meet Western Power’s sensitivity requirements.
2) Phase under voltage pickup. All phase voltages must be below this setting for the phase under voltage function to pickup. The phase under voltage pickup should be:
    a) Above a lower boundary just above zero. The lower the setting of pickup, the less effective the SOTF function will be. If the pickup is set close to zero, only earths placed close to the busbar would cause SOTF to operate.
    b) Below an upper boundary defined by the voltage sag caused by energising a load.
    c) A standard setting of 40% of the nominal operating voltage has been used with success. This setting:
        i) Permits working earths within the radius of interest to be detected
        ii) Differentiates between load inrush current and fault current caused by working earths
3) A time delay before SOTF is armed is required when the VT used for SOTF restraint is energised by closing the circuit breaker. The time delay must be sufficient to allow the protection relay time to measure voltage and restrain SOTF. Without the time delay the SOTF function could incorrectly operate for inrush.

6.4.3.11 Transformer Mechanical Trips

Transformer mechanical trips are brought through the protection relay for the purposes of ensuring that all transformer trips originate from the protection relay. This has the following benefits:

1) Local flagging for mechanical trips does not require separate flagging relays
2) The dynamic disturbance recorder can compare mechanical trips with the operation of relay functions

[51] Historically when *voltage* restraint was not used a SOTF allowance factor of 3 was used to allow for cold load inrush. A factor up to 6 would have been used if loads were known to draw large inrushes. Unrestrained SOTF operations have been experienced at settings based on 150% of maximum load.

Mechanical trips depend on the type and manufacturer of the transformer. The mechanical trips must be arranged to compliment each other (e.g. the HV winding temperature trip must be included in the alternate protection scheme from the LV winding temperature).

The zone substation transformer HV winding temperature is used for alarming only. It is not used to trip the transformer.

6.4.3.12 Circuit Breaker Failure

The purpose of circuit breaker failure (CB Fail) is to detect when the tripping of a circuit breaker fails to clear its contribution to a fault. This can be caused either by the circuit breaker failing to open or by a small zone fault.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of CB Fail.

6.4.3.13 Local Metering

Local metering is a standard function in all main protection relays. Refer to Engineering Design Instruction – Substation Secondary Systems Design for local metering requirements.

6.4.3.14 Remote Metering

Remote metering is a standard function in one main protection relay. Refer to Engineering Design Instruction – Substation Secondary Systems Design for remote metering requirements.

6.4.3.15 Circuit Breaker Wear Monitoring

The purpose of the circuit breaker wear function is to assist in the scheduling of circuit breaker maintenance. Refer to Section 8 – Circuit Breaker Protection for more information.

6.4.3.16 Trip Circuit Supervision

The purpose of trip circuit supervision (TCS) is to supervise the integrity of the circuit breaker trip coil. The trip coil is supervised when in both the open and closed state. TCS also supervises the integrity of some of the associated secondary wiring

Refer to Engineering Design Instruction – Substation Secondary Systems Design for a detailed description of TCS.

6.4.3.17 Dynamic Disturbance Recorder

The dynamic disturbance recorder (DDR) must be configured so that the recorder captures the:

1) Pre fault waveforms.
2) Post fault waveforms which include circuit breaker failure operations.
3) Post fault waveforms which include clearance by downstream devices within the main protection system operating zone.

Dynamic disturbance recording is a standard function in all main protection relays.

6.4.3.18 Sequence of Events Recorder

The sequence of events recorder (SER) monitors what occurs within the relay during both normal operation and faults. When the SER is triggered, a record is created of these events. A protection trip must trigger the SER.

To simplify the event record and minimise the chance of the relay failing, the following guidelines should be followed when choosing what is to appear in the SER:

1) Do not include word bit outputs of directional elements

2) Do not include word bits that may change state frequently under normal conditions, or near the edge of such conditions

Sequence of event recording is a standard function in all main protection relays.

6.4.3.19 Time Synchronisation

The protection relays must be configured to receive the Irig B time code or the SNTP time signal when available. The Irig B clock and the SNTP server provide accurate time stamping for fault events. Irig B is more accurate and preferred when no additional wiring is required.

Irig B is standard for all DNP relays. Irig B is standard on IEC61850 relays when additional wiring is not required (e.g. zone substation HV relays). When additional wiring is required SNTP is used (e.g. zone substation LV relays).

6.4.3.20 Defective Alarms

Protection defective means the protection scheme is defective. At DNP sites this is hardwired from the IED to the RTU and means that the IED is defective. At IEC61850 sites it includes failure of the IEC61850 signalling.

Device defective means that the hardware is defective. Examples include IEDs, controllers and gateways.

Defective alarms use normally open contacts when hardwired.

6.5 Appendix A – Transformer Design Requirements

Functions		Operation						Indication					
Function Name	ANSI	Initiation		Selection		Resetting		Operation		Selection		Resetting	
		A/R	CB Fail	Local	EPCC	Local	EPCC	Local	EPCC	Local	EPCC	Local	Self
Bias differential	87		Yes			Latched		Yes	Yes			Yes	
High impedance circulating current			Yes			Latched		Yes	Yes			Yes	
HV IDMT overcurrent	51		Yes			Self		Yes	Yes			Yes	
LV IDMT overcurrent	51		Yes			Self		Yes	Yes			Yes	
TV IDMT overcurrent	51		Yes			Self		Yes	Yes			Yes	
Instantaneous overcurrent	50		Yes			Latched		Yes	Yes			Yes	
Transformer paralleling overcurrent	50		Yes	Yes	Yes	Self		Yes	Yes	Yes	Yes	Yes	
Negative phase sequence	46		Yes			Self		Yes	Yes			Yes	
HV restricted earth fault	64		Yes			Latched		Yes	Yes			Yes	
LV restricted earth fault	64		Yes			Latched		Yes	Yes			Yes	
TV restricted earth fault	64		Yes			Latched		Yes	Yes			Yes	
LV standby earth fault	64		Yes			Self		Yes	Yes			Yes	
TV standby earth fault	64		Yes			Self		Yes	Yes			Yes	
Circuit breaker failure	52					Latched		Yes	Yes			Yes	
Local metering	HMI												
Remote metering	77												
Circuit breaker wear monitoring	94.1			Yes						Yes			

Trip circuit supervision	TCM					Self		Yes	Yes				Yes
Dynamic disturbance recorder	DDR												
Sequence of events recorder	SER												
Time Synchronisation	CLK												
Protection defective						Self		Yes	Yes				Yes
Device defective						Self		Yes	Yes				Yes
Mechanical Trips													
Main tank buchholz			Yes			Latched		Yes	Yes			Yes	
HV winding temperature			Yes			Latched		Yes	Yes			Yes	
Earthing transformer pressure			Yes			Latched		Yes	Yes			Yes	
Tap changer pressure			Yes			Latched		Yes	Yes			Yes	
Main tank pressure			Yes			Latched		Yes	Yes			Yes	
Oil temperature			Yes			Latched		Yes	Yes			Yes	
LV winding temperature			Yes			Latched		Yes	Yes			Yes	
LV winding temperature (terminal stations)			Yes			Latched		Yes	Yes			Yes	
TV winding temperature			Yes			Latched		Yes	Yes			Yes	
Earthing Transformer oil temperature			Yes			Latched		Yes	Yes			Yes	

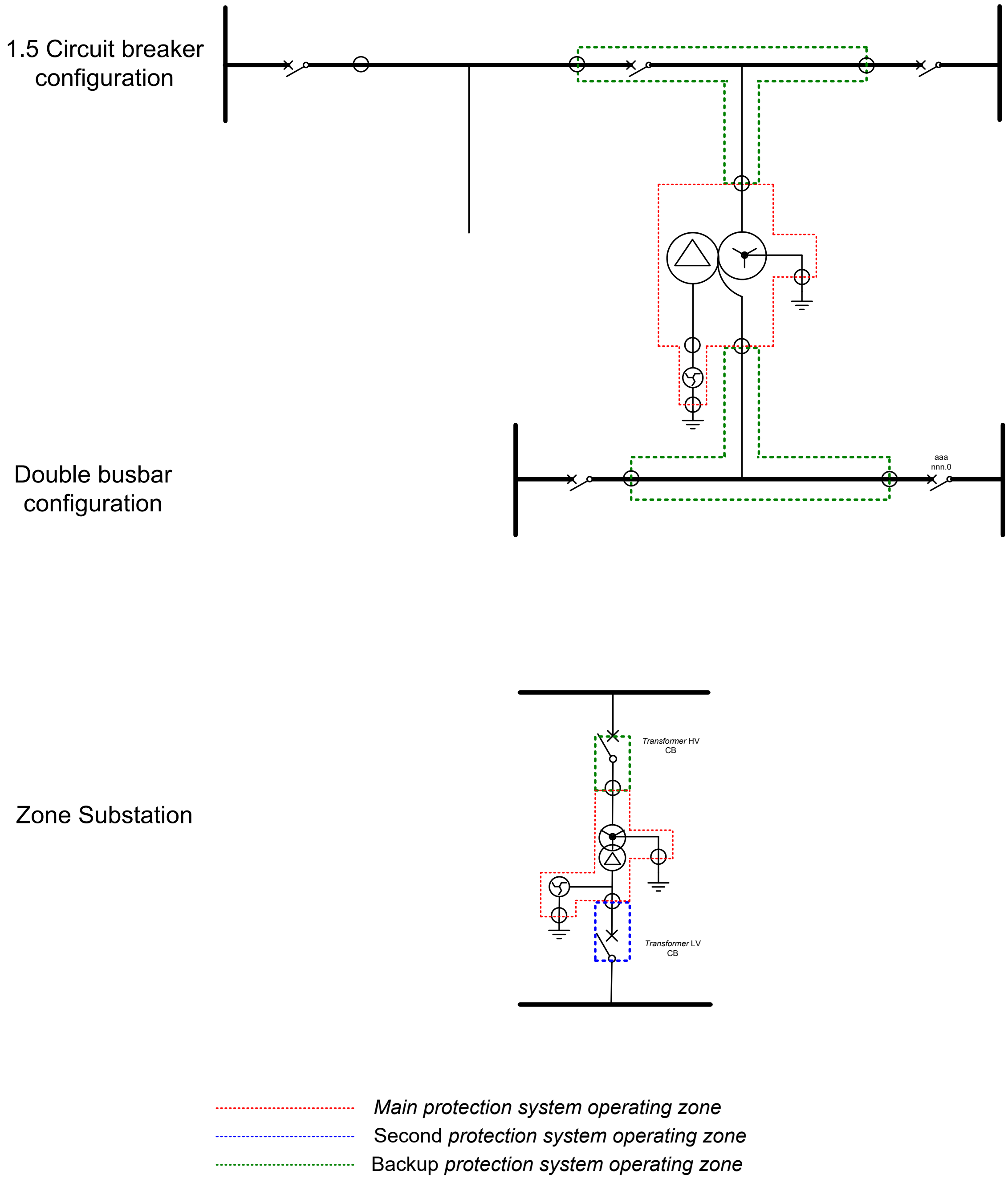
Note: Grey areas signify ‘No’ or ‘Not Applicable’

Note: Relay Resetting includes both contact and word bit resetting. Local resetting includes push buttons on the relay or from an HMI. Transformer faults latch, system faults self reset.

Note: HV winding temperature is used for indication only for zone substation transformers. At terminal stations the HV, LV and TV winding temperatures trip the transformer.

6.6 Appendix B – Roles and Responsibilities

6.7 Appendix C – Operating zones



6.8 Appendix D – Brownfield Main Protection System Requirements

The main protection 1 and main protection 2 functions are arranged in such a way that they complement each other. The following principles shall be applied:

1) Unit protection:
    a) At least one unit protection scheme shall be included in the main transformer protection system. Where only one unit protection scheme is applied, the following functions must be included in the other main protection scheme:
        i) HV IDMT overcurrent
        ii) Instantaneous overcurrent
        iii) Buchholz
        iv) Tap changer pressure relays

        This ensures that the non-unit main protection scheme is capable of both high speed operation and sensitive fault detection.
    b) Second unit protection. A second unit protection scheme shall be applied on the following:
        i) Terminal station transformers
        ii) Zone substation transformers
2) HV IDMT overcurrent must be included in the same main protection scheme as the circulating current protection scheme when protecting an autotransformer. The circulating current protection scheme does not detect phase to phase faults on the tertiary.
3) Restricted earth fault protection must be included for a transformer winding with a solidly earthed neutral. This is to provide coverage for earth faults that may be below the sensitivity of the biased differential protection. These two protection functions complement each other so they must be included in the same main protection scheme.
4) Because both the winding temperature and oil temperature relays measure oil temperature, they must be included in different main protection schemes.
5) Because both the winding temperature and HV overcurrent provide overload protection, they must be included in different main protection schemes.

    Note that the HV overcurrent protection only provides limited backup to the winding temperature depending on the:
    a) HV IDMT overcurrent setting. This is usually 150% of the transformer rating
    b) Winding thermal gradient
6) Because both the tank pressure and Buchholz provide a form of large oil surge sensing they must be included in different main protection schemes.
7) In Zone substations the transformer protection systems may also provide the main LV busbar and / or the second LV busbar and feeder protection systems. The functions providing these protections are:
    a) LV IDMT overcurrent and LV earth fault on battery 1 provide the LV busbar main protection system

b) HV IDMT overcurrent and LV standby earth fault on battery 2 provide the LV busbar and feeder second protection system

The earth fault functions are required because:

c) The earthing transformer reduces the magnitude of the earth fault currents below the sensitivity of the overcurrent relays.

d) The HV IDMT overcurrent on battery 2 providing the LV busbar second protection system only detects $1/\sqrt{3}$ of the LV earth fault current. The LV standby earth fault function is provided by and located with the transformer HV main protection 2 scheme.

This protection arrangement will always apply regardless of any busbar protection systems.

6.9 Appendix E – Role of Protection Functions

Role	Function
High speed fault clearance	Biased Differential
	Circulating current
	HV Restricted Earth Fault
	LV Restricted Earth Fault
	Main Tank Pressure
	Tap Changer Pressure
	Earthing Transformer Pressure
	Instantaneous Overcurrent
Low level fault detection	Circulating Current
	HV Restricted Earth Fault
	LV Restricted Earth Fault
	TV Restricted Earth Fault
	LV Standby Earth Fault
	TV Standby Earth Fault
	Main Tank Buchholz
Overload protection	HV IDMT Overcurrent
	LV IDMT Overcurrent
	TV IDMT Overcurrent
	HV Winding Temperature
	LV Winding Temperature
	Oil Temperature
System backup	HV IDMT Overcurrent
	LV IDMT Overcurrent
	TV IDMT Overcurrent
	LV Earth Fault
	TV Earth Fault
	LV Standby Earth Fault
	TV Standby Earth Fault

6.10 Appendix F – Short-circuit Apparent Power

Table 2 below is from AS 60076.5 2012 and is used for thermal rating calculations (I^2t). Western Power uses the current European practice values.

Table 2 – Short-circuit apparent power of the system

Highest voltage for equipment, U_m kV	Short-circuit apparent power MVA	
	Current European practice	Current North American practice
7,2; 12; 17,5 and 24	500	500
36	1 000	1 500
52 and 72,5	3 000	5 000
100 and 123	6 000	15 000
145 and 170	10 000	15 000
245	20 000	25 000
300	30 000	30 000
362	35 000	35 000
420	40 000	40 000
525	60 000	60 000
765	83 500	83 500
NOTE If not specified, a value between 1 and 3 should be considered for the ratio of zero-sequence to positive-sequence impedance of the system.		

Since 1970 all transformer windings have been designed to withstand all faults on their lowest taps. Prior to 1970 the design was done on the nominal tap however for reasons of mechanical strength extra copper was and still is used. The extra copper increases the thermal withstand capability of the HV winding to cater for faults when on the lower tap. It is therefore safe to ignore the thermal effects on the HV winding and concentrate wholly on the LV winding for delta – star and star-delta-star transformers.

Tertiary delta windings were sometimes under rated, however attention is now given to their mechanical strength which ensures a thermally stable design.

6.11 Appendix G – 22 kV Earthing Transformer Impedance Calculation

6.11.1 22 kV High Impedance Earthing Transformer

Western Power specifies a 35 Ω/phase earthing transformer to provide a zero sequence path and regulate fault current. The fault current will be:

$Z_{Base} = 22^2 / 100 = 4.84$

35 Ω/phase = 35 / 4.84 = 7.23 pu

Transformer impedance = 0.6 pu

Neglecting the source impedance at the transformer HV

$$3I_0 = \left(\frac{3 * 100}{7.23 + 0.6}\right) * \left(\frac{1}{\sqrt{3} * 22}\right) = 1.005\text{kA}$$

A 35 Ω/phase earthing transformer will give a total earth fault current of $3I_0$ = 1.005 kA (335 A /phase). The HV source impedance will reduce this to around the typical 300 A / phase or 900 A total. The earthing transformers are rated at $3I_0$ = 1200 A for 10 seconds which is above the $3I_0$ of 1005 A.

6.11.2 22 kV Low Impedance Earthing Transformer

Western Power specifies a 2.5 Ω/phase low impedance earthing transformer to provide a zero sequence path and effectively earth the distribution system. These transformers are required where SWER (single phase) systems are used. These are located in the South West where the 132 kV fault levels are typically below 1000 MVA ($Z_{Source} \geq 0.1$ pu). The fault current will be:

$Z_{Base} = 22^2 / 100 = 4.84$

2.3 Ω/phase = 2.5 / 4.84 = 0.517 pu

Transformer impedance = 0.6 pu

Z_{Source} = 0.1 pu

$$3I_0 = \left(\frac{3 \text{ x } 100}{0.517 + 0.6 + 0.1}\right) * \left(\frac{1}{\sqrt{3} * 22}\right) = 6.47 \text{ kA}$$

This fault current will be reduced by the impedance of the feeder conductor. These earthing transformers are rated at $3I_0$ = 10,000 A for 10 seconds which is above the $3I_0$ of 6.47 kA.

6.12 Appendix H – Restricted Earth Fault

6.12.1 Earthed Star Point Winding

Transformer restricted earth fault (REF) protection is used to overcome this insensitivity problem. It compares the $3I_0$ flowing in the star point of transformer winding with the sum of the I_0 currents in the three phases. This always sums to zero in a non-faulted winding.

Figure 6.4 – REF in-zone fault

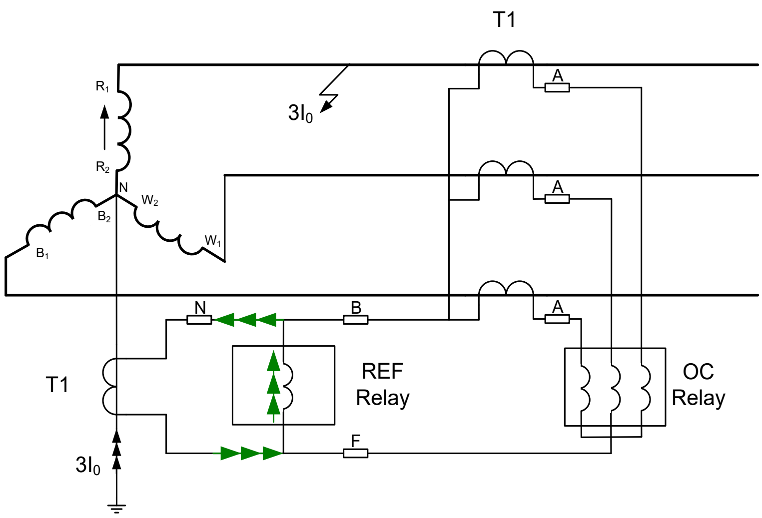
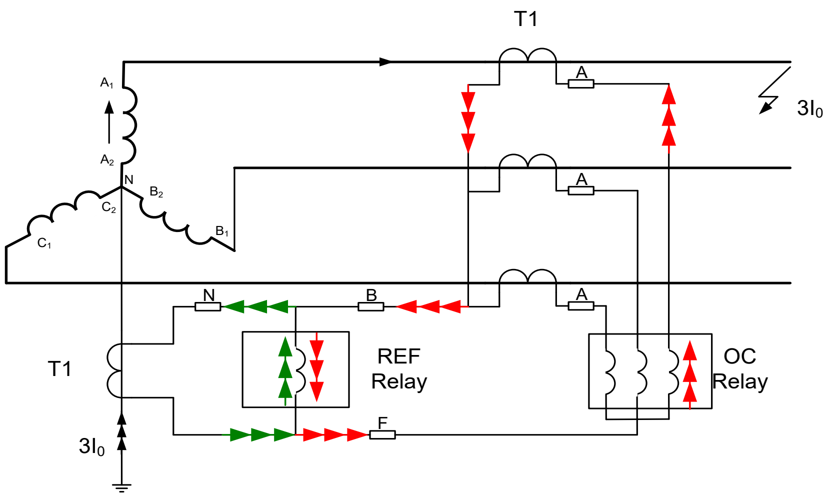


Figure 6.5 – REF out-of-zone fault



6.12.2 Unearthed Star Point and Delta Windings

If the winding is unearthed, eg. an HV delta or unearthed star winding, the sum of the three phase currents (= 3I0) will be zero unless there is an earth fault on the winding itself.

Figure 6.6 – Unearthed star with in-zone fault

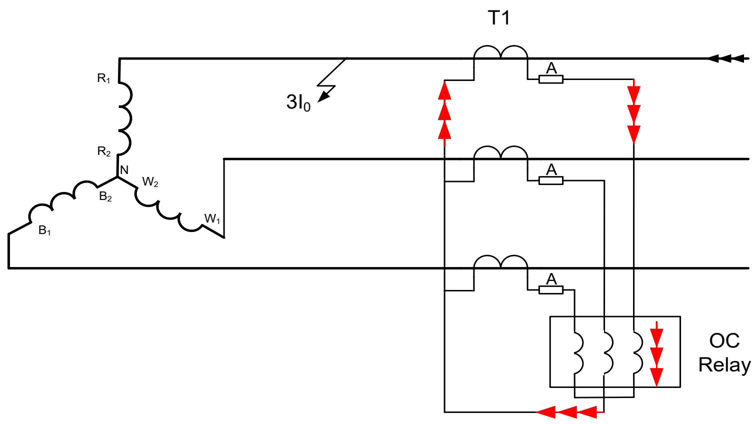
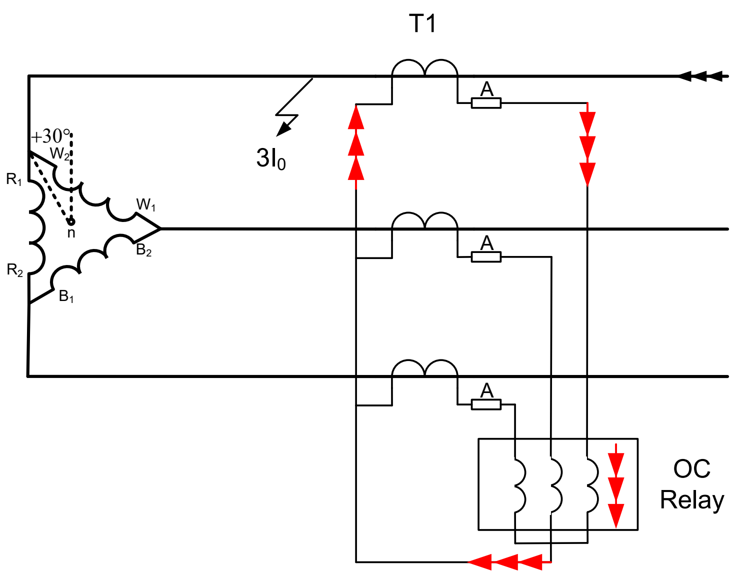


Figure 6.7 – Delta with in-zone fault



7 Bus Section Protection

7.1 Introduction

The purposes of this section are to:

1) Define at a high level the functional requirements for bus section protection in Western Power terminal stations and zone substations.

2) Capture information which explains the reasoning behind the bus section protection design and settings

7.2 Scope

This section applies to bus section circuits within Western Power terminal stations and zone substations.

Bus sections are used to connect two busbars in series. Bus couplers are used to connect two busbars in parallel. Unless otherwise noted, the contents of this section also apply to bus couplers.

7.3 Functional Requirements

The functional requirements for the bus section protection systems are:

1) Allow two sections of busbar to be connected and disconnected

2) Detect and clear small zone faults within times specified by the Technical Rules

7.4 Bus Section Protection

7.4.1 Introduction

The primary purpose of the bus section protection systems is to improve reliability by limiting an outage to the faulted section of busbar. Other purposes include control and monitoring to facilitate operation of the busbar. In 1.5 circuit breaker and double busbar configurations bus couplers are used to select circuits to one of the busbars.

7.4.2 Design Requirements

Section 7.5 outlines the design requirements for standard functions and site specific functions.

7.4.2.1 Distribution Main Protection System

The main protection system protecting the bus section equipment shall comprise one of the following:

1) A busbar main protection scheme when busbar protection CT cores are available.

   At new sites the bus section equipment is included in the busbar main protection system. The bus section relay is not intended to operate for busbar faults; however it does provide some system backup.

2) Transformer overcurrent protection.

7.4.2.2 Distribution Backup Protection System

Bus sections at distribution voltages have only 1 set of CTs which creates a small zone. The bus section's second protection system operating zone is defined by the small zone between the bus section circuit breaker and bus section current transformer. Refer to section 7.6.

The second protection system is provided by the transformer overcurrent protection.

7.4.2.3 Transmission Main Protection System

At developed sites the bus section equipment is included in the busbar main protection systems 1 & 2. The bus section relay is not intended to operate for busbar faults; however it does provide some system backup

7.4.3 Standard Functions

The following standard functions are provided for all bus section applications.

7.4.3.1 IDMT Overcurrent

Inverse definite minimum time (IDMT) overcurrent is normally set above primary plant ratings and is not intended to operate for faults. Setting the relay to operate for faults would introduce a grading step which would be difficult to achieve at most sites. IDMT overcurrent is largely provided for contingency situations.

7.4.3.1.1 Settings

The settings are selected to meet the following requirements:

1) Pickups determined by the following limits:
    a) Lower limit: The lower limit is calculated from:
        i) Must be above the circuit breaker rating so operation of the circuit breaker is not restricted.
        ii) Allowance for relay errors.
        iii) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements for a fault at the bus section circuit breaker.
2) The time multiplier setting (TMS) must:
    a) Allow discrimination with other protection systems

7.4.3.2 Switch On To Fault

7.4.3.2.1 Purpose

The purpose of switch on to fault (SOTF) is to clear fault current caused by closing the associated circuit breaker onto a set of working earths. The working earths would normally be applied to or very near the busbar.

SOTF comprises a single phase definite time overcurrent element and associated logic.

7.4.3.2.2 Functionality

SOTF can be summarised as follows:

1) The SOTF function shall be “armed” when the circuit breaker has been opened and the standard SOTF enable time of 60 seconds has elapsed. The circuit breaker is determined to be open when:
    a) Current is below a set level in all phases, and
    b) The circuit breaker auxiliary contacts indicate that the circuit breaker is open
2) The SOTF function shall be "disarmed" when the circuit breaker has been closed and the standard SOTF duration time of 0.6 seconds has elapsed. The circuit breaker is determined to be closed when:
    a) Current is above a set level in at least one phase, or
    b) The circuit breaker auxiliary contacts indicate that the circuit breaker is closed
3) SOTF shall be voltage restrained when a VT is available. Restraint for load inrush conditions and VT failure is provided by a voltage element. Restraint for VT failure is provided by logic.

7.4.3.2.3 SOTF Settings

The SOTF settings are selected to meet the following requirements:

1) Pickups are determined by the following limits:
    a) The lower limit of the setting is calculated from:
        i) Overcurrent pickup
        ii) A margin. The SOTF margin ensures that the pickup of SOTF is above the maximum intended steady state load. This avoids the sequential event buffer being filled with uninteresting changes. The SOTF margin is normally set to 130% of the expected load.
        iii) Relay errors.

        In practice, a small setting may be acceptable, if a very secure restraint for cold load inrush and VT failure conditions is possible [52].
    b) Upper limit: 50% of the bolted 3 phase fault level at the associated busbar under minimum system conditions.
2) Phase under voltage pickup. All phase voltages must be below this setting for the phase under voltage function to pickup. The phase under voltage pickup must be:
    a) Above a lower boundary just above zero. The lower the pickup is set, the less effective the SOTF function will be. If the pickup is set close to zero, only earths placed close to the busbar will cause SOTF to operate.
    b) Below an upper boundary defined by the voltage sag caused by energising a heavily loaded, healthy busbar.
    c) A standard setting of 40% of the nominal operating voltage has been used with success. This setting:
        i) Permits working earths within the radius of interest to be detected

[52] Historically when *voltage* restraint was not used a SOTF allowance factor of 3 was used to allow for cold load inrush. A factor up to 6 would have been used if loads were known to draw large inrushes. Unrestrained SOTF operations have been experienced at settings based on 150% of maximum load.

ii) Differentiates between load inrush current and fault current caused by working earths

3) A time delay before SOTF is armed is required when the VT used for SOTF restraint is energised by closing the circuit breaker. The time delay must be sufficient to allow the protection relay time to measure voltage and restrain SOTF. Without the time delay the SOTF function could incorrectly operate for inrush.

7.4.3.3 Circuit Breaker Failure

The purpose of circuit breaker failure (CB Fail) is to clear a fault when attempting to trip a circuit breaker fails to clear its contribution to a fault. Failure to clear the fault contribution can be caused either by the circuit breaker failing to open or by a small zone fault.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of CB Fail.

7.4.3.4 Local Metering

Refer to Engineering Design Instruction – Substation Secondary Systems Design for local metering requirements.

7.4.3.5 Remote Metering

Refer to Engineering Design Instruction – Substation Secondary Systems Design for remote metering requirements.

7.4.3.6 Circuit Breaker Wear Monitoring

The purpose of circuit breaker wear monitoring is to assist in the scheduling of circuit breaker maintenance.

Settings are chosen to allow the relay to calculate and accumulate circuit breaker wear information during each circuit breaker opening action.

It is important to preserve accumulated breaker monitoring information during routine maintenance. Therefore it is a requirement that maintenance staff be provided with a means of temporarily disabling the recording of such data.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of circuit breaker wear monitoring.

7.4.3.7 Trip Circuit Supervision

The purpose of trip circuit supervision (TCS) is to supervise the integrity of the circuit breaker trip coil. The trip coil is supervised when in both the open and closed state. TCS also supervises the integrity of some of the associated secondary wiring.

Refer to Engineering Design Instruction – Substation Secondary Systems Design for a detailed description of TCS.

7.4.3.8 Dynamic Disturbance Recorder

The dynamic disturbance recorder (DDR) must be configured so that the recorder captures the:

1) Pre fault waveforms.

2) Post fault waveforms which include circuit breaker failure operations.

3) Post fault waveforms which include clearance by downstream devices within the main protection system operating zone.

7.4.3.9 Sequence of Events Recorder

The sequence of events recorder (SER) monitors what occurs within the relay during both normal operation and faults. When the SER is triggered, a record is created of these events. A protection trip must trigger the SER.

To simplify the event record and minimise the chance of the relay failing, the following guidelines must be followed when choosing what is to appear in the SER:

1) Do not include word bit outputs of directional elements

2) Do not include word bits that may change state frequently under normal conditions, or near the edge of such conditions

7.4.3.10 Time Synchronisation

The protection relays must be configured to receive the Irig B time code or the SNTP time signal when available. The Irig B clock and the SNTP server provide accurate time stamping for fault events. Irig B is more accurate and preferred when no additional wiring is required.

Irig B is standard for all DNP relays. Irig B is standard on IEC61850 relays when additional wiring is not required (e.g. zone substation HV relays). When additional wiring is required SNTP is used (e.g. zone substation LV relays).

7.4.3.11 Defective Alarms

Protection defective means the protection scheme is defective. At DNP sites this is hardwired from the IED to the RTU and means that the IED is defective. At IEC61850 sites it includes failure of the IEC61850 signalling.

Device defective means that the hardware is defective. Examples include IEDs, controllers and gateways.

Defective alarms use normally open contacts when hardwired.

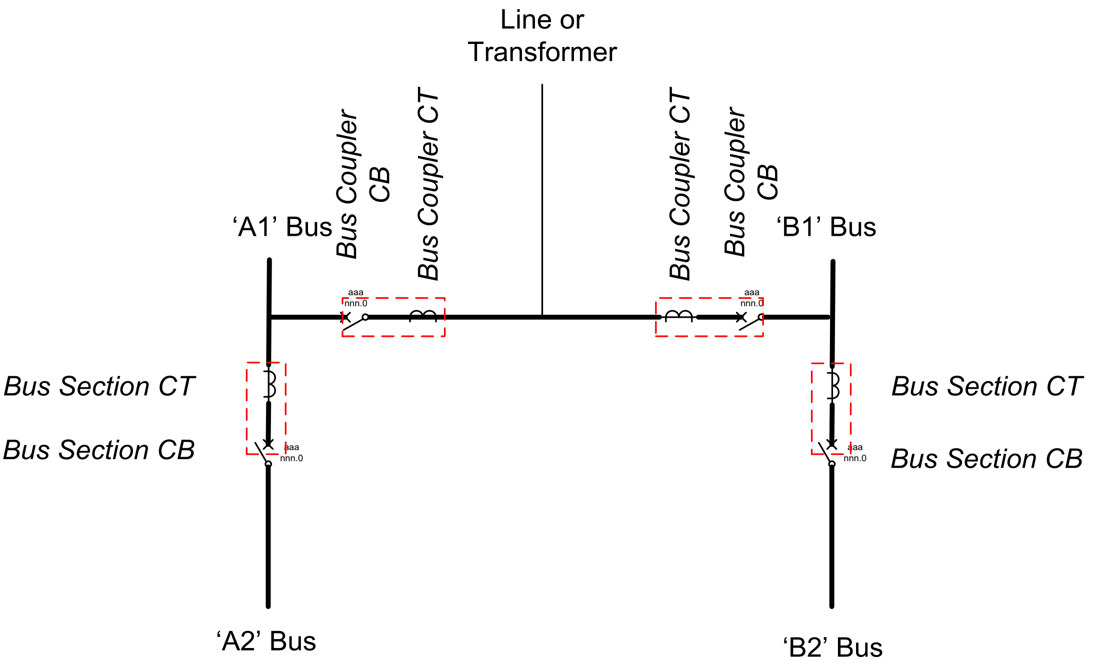
7.5 Appendix A – Bus Section Design Requirements

Functions		**Operation**						**Indication**					
Function Name	**ANSI**	**Initiation**		**Selection**		**Resetting**		**Operation**		**Selection**		**Resetting**	
		A/R	**CB Fail**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**Self**
IDMT overcurrent	51		Yes			Self		Yes	Yes			Yes	
IDMT earth fault	64		Yes			Self		Yes	Yes			Yes	
Switch on to fault	SOTF		Yes			Self		Yes	Yes			Yes	
CB failure	52					Latched		Yes	Yes			Yes	
Local metering	HMI												
Remote metering	77												
Circuit breaker wear monitoring	94.1			Yes						Yes			
Trip circuit supervision	TCM					Self		Yes	Yes				Yes
Dynamic disturbance recorder	DDR												
Sequence of events recorder	SER												
Time Synchronisation	CLK												
Protection Defective						Self		Yes	Yes				Yes
Device Defective						Self		Yes	Yes				Yes

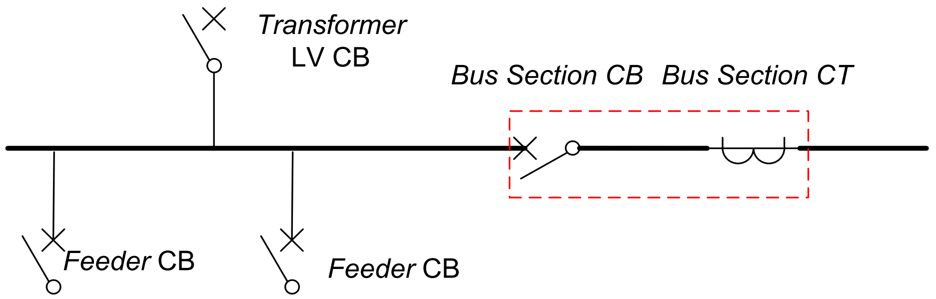
Note: Grey areas signify ‘No’ or ‘Not Applicable’

Note: Relay Resetting includes both contact and word bit resetting

7.6 Appendix B – Operating zones



Transmission Voltage Backup Protection System Operating Zones



Distribution Voltage Backup Protection System Operating Zones

8 Circuit Breaker Protection

8.1 Introduction

The purposes of this standard are to:

1) Define at a high level the functional requirements for circuit breaker protection in Western Power terminal stations and zone substations
2) Capture information which explains the reasoning behind the circuit breaker protection design and settings

8.2 Scope

This standard applies to circuit breakers within a Western Power terminal station or zone substation.

8.3 Functional Requirements

The functional requirements for the circuit breaker protection systems are:

1) Detect and clear faults in the circuit breaker operating zone.
2) Detect and clear faults within times specified by the Technical Rules.
3) Coordinate with upstream and downstream protection systems.
4) Clear faults within the thermal limits of associated primary equipment, including the power transformer.

8.4 Circuit Breaker Protection

8.4.1 Introduction

Circuit breakers are used to:

1) Isolate faulty equipment from the rest of the system
2) Isolate primary plant so that maintenance and construction can be performed
3) Reconfigure the system

Various functions provided by the protection relays are used to allow these tasks to be performed safely and reliably.

8.4.1.1 Check Synchronism

Check synchronism (sync check) is used to prevent closing of a circuit breaker onto two unsynchronised systems.

8.4.1.1.1 System Conditions Requiring Sync Check

Sync check is generally not required at distribution voltages. At transmission voltages sync check is required as outlined below:

1) Substations that have generator connections require sync check. The closing of a circuit breaker should not result in a sudden change in the power from the generator of more than 0.5 pu of the rating of the generator [53].
2) Substations require sync check where an outage of 2 or less circuits forms a generation island.
3) Intermediate substations in meshed systems generally do not require sync check. If an outage of more than two circuits is required to form a generation island, check sync is usually not required.

8.4.1.2 Automatic Reclose

The purpose of automatic reclose is to automatically restore supply following a transient fault. Delayed automatic reclose (DAR) is standard on the distribution system. DAR and high speed single pole automatic reclose (HSSPAR) are not standard functions on the transmission system and will only be provided when requested by transmission planning.

The following automatic reclose settings are specified by the distribution or transmission planning engineer:

1) Dead time

   The following factors affect the selection of the dead time [54]:

   a) System stability and synchronism – in order to reclose without loss of synchronism, the dead time must be kept to a minimum.

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[53] IEEE Screening Guide for Planned Steady-State Switching Operations to Minimise Harmful Effects on Steam Turbine Generators", IEEE Trans., Vol. PAS-99, No.4, pp 1519-1521, July/August 1980

[54] *Network Protection and Automation*, Areva, First edition July 2002, p. 221

b) Type of load – the dead time must be long enough to allow industrial motor circuits to trip for loss of supply.

c) Circuit breaker characteristics – the dead time must be long enough to allow any trip free mechanisms to reset and the close mechanisms to fully close.

d) Fault path de-ionisation time – the dead time must be long enough to allow any ionised air to disperse after a protection trip. The dead time must be longer than the time required to totally extinguish the arc.

e) Protection reset time – the dead time must be long enough to allow the protection relays to completely reset.

2) Reclaim time

The following factors affect the selection of the reclaim time:

a) Protection operating time. The reclaim time must allow the protection relays time to operate when the circuit breaker is closed on a permanent fault.

b) Circuit breaker characteristics. The reclaim time must allow a spring closed circuit breaker enough time to fully wind its spring. Otherwise the circuit breaker could be reclosed with a partly wound spring.

3) Number of Shots

The following factors affect the selection of the number of shots:

a) Circuit breaker limitations – the circuit breaker must be able to perform a number of trip and close operations in quick succession. Automatic reclose will affect the maintenance cycle.

b) System conditions – areas affected by a large number of outages caused by lightning or bird strikes are good candidates for single shot automatic reclose.

c) Thermal rating of equipment – Transformers are designed with a 2 second rating at currents defined by the operating voltage [55]. This rating and the total fault clearance time limits the number of shots on distribution feeders in the metropolitan area to one shot. Feeders in country areas with lower fault levels may be able to accommodate two or three shots.

[55] AS 60076.5 2012 clause 4.1.3

8.4.1.3 Delayed Automatic Reclose

Delayed automatic reclose (DAR) schemes trip and reclose three poles simultaneously. The reclosing of the circuit breakers is delayed by more than 1 second from the trip operation. DAR is applied when:

1) There is little chance of the two sides of the circuit breaker drifting out of synchronism and

2) A higher quality of supply is required.

8.4.1.3.1 Operating Principle

The following is a typical single (1 shot) DAR cycle:

1) The protection relay detects a fault and:

    a) Trips the circuit breaker

    b) Initiates the DAR dead time

2) When the dead time has expired:

    a) The circuit breaker is reclosed

    b) The reclaim time is initiated. Note that the reclaim time is sometimes referred to as the reset time.

3) If the fault is still present the circuit breaker will trip and the automatic reclose function will lock out.

4) If the fault is not present and the reclaim time expires, the automatic reclose function will reset.

Multiple shot DAR will repeat this cycle until either:

5) The reclose is unsuccessful and the number of shots is reached causing the DAR function to lock out

6) The reclose is successful and the DAR function resets

Figure 8.1 and Figure 8.2 show the relationship between the protection operation, circuit breaker operation and automatic reclosure cycle.

Figure 8.1 – Single shot automatic reclosure cycle for transient fault [56]

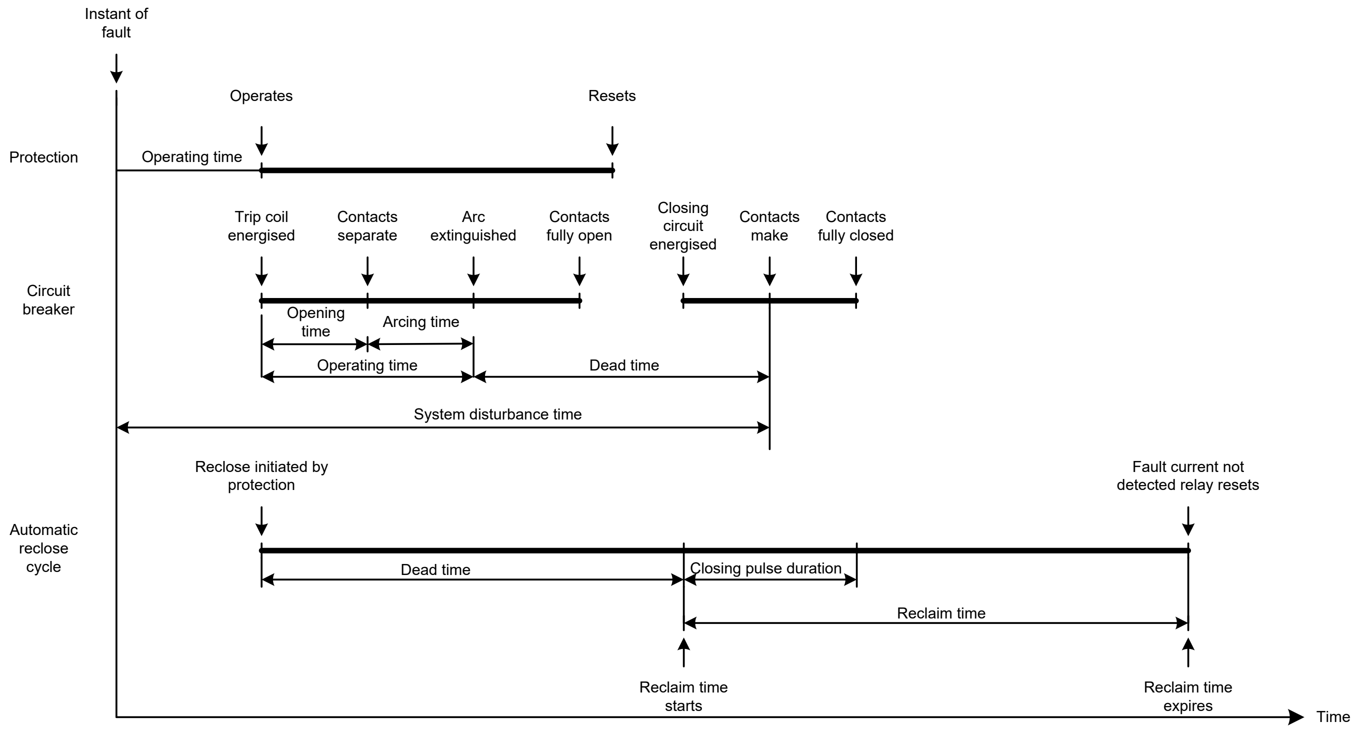
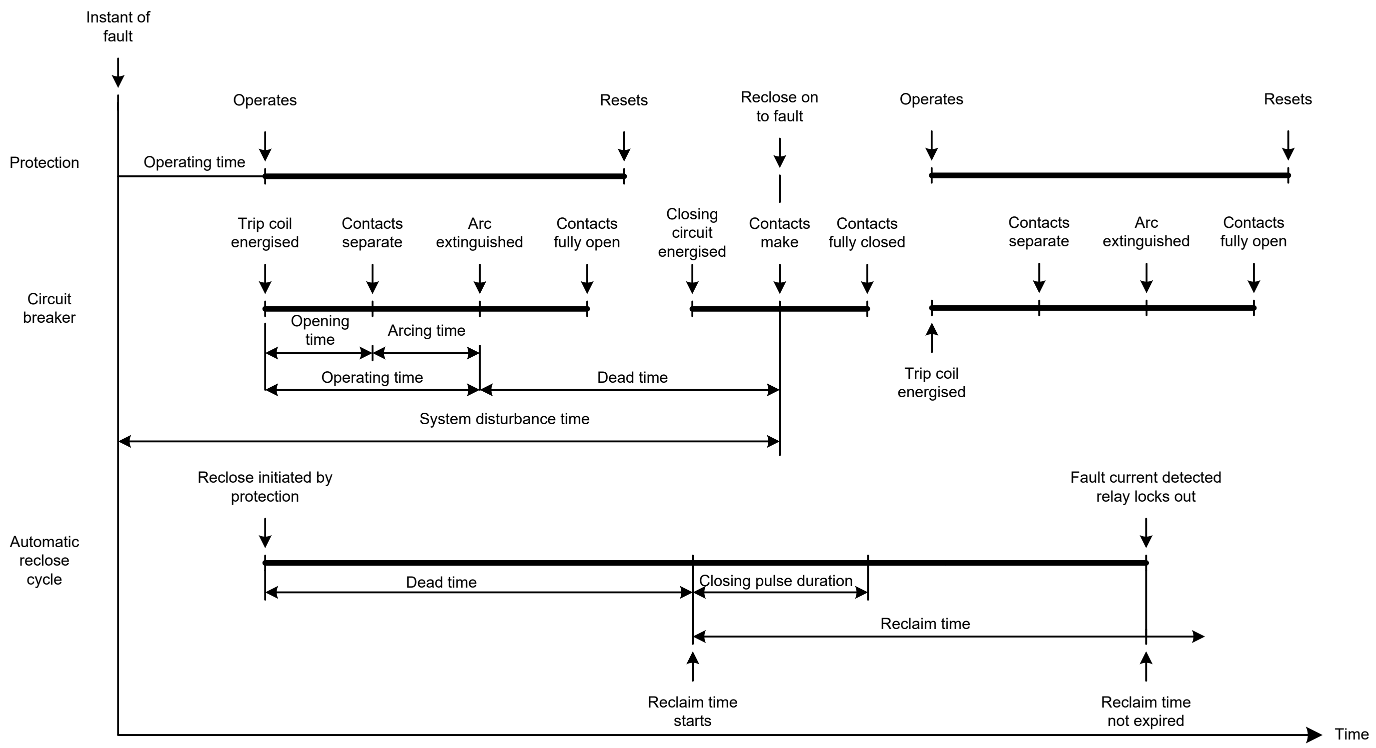


Figure 8.2 – Single shot automatic reclosure cycle for permanent fault



[56] *Network Protection and Automation*, Areva, First edition July 2002, p. 220

8.4.1.4 High Speed Single Pole Automatic Reclose

High speed single pole automatic reclose (HSSPAR) schemes trip and reclose each pole individually following a single phase to earth fault. The reclosing of the circuit breakers is delayed by less than 1 second from the trip operation.

8.4.1.4.1 1.5 Circuit Breaker Application

In a 1.5 circuit breaker application a circuit breaker is designated as either the:

1) HSSPAR circuit breaker, which is tripped and reclosed on the faulted phase

2) Non-HSSPAR circuit breaker, which trips all 3 poles

If the HSSPAR circuit breaker is out of service, the line circuit will trip and lockout as a 3 pole operation.

8.4.1.4.2 Operating Principle

HSSPAR operates on the same general principle as DAR. The following is a representation of the standard single 1 shot HSSPAR cycle in a 1.5 circuit breaker terminal station:

1) The line protection relay picks up and:
    a) Sends a single pole trip to the HSSPAR circuit breaker (e.g. 911.0)
    b) Initiates the HSSPAR dead time for the faulted phase
    c) Sends a three pole trip to the non-HSSPAR circuit breaker (e.g. 913.0)
2) When the HSSPAR dead time expires:
    a) The HSSPAR circuit breaker recloses the faulted phase
    b) The HSSPAR reclaim time is initiated. Note that the reclaim time is sometimes referred to as the reset time.
3) If the fault is still present the HSSPAR circuit breaker will trip and the automatic reclose function will lock out.
4) If the fault is not present and the reclaim time expires, the automatic reclose function will reset.
5) The HSSPAR relay will send a 3 pole close signal to the non-HSSPAR circuit breaker after the HSSPAR circuit breaker has been successfully reclosed for 10 seconds. Note that this is not 10 seconds after the HSSPAR circuit breaker reclaim time has expired.

8.4.1.4.3 Adaptive Dead time

Adaptive dead time (ADT) allows reclosure at one line end following successful reclosure at the other line end. One line end has a standard defined dead time. The other line end, which is usually the one connected to the stronger source, has an ADT relay measuring line volts. If healthy three phase line volts are present, indicating successful reclosure at the defined dead time end, the ADT circuit breaker is allowed to reclose. The advantage of ADT is that the ADT circuit breaker, and therefore the generators supplying the fault from that end, is not unnecessarily stressed if the fault persists.

A disadvantage is that a two line substation could be blacked out due to a lack of automatic reclose. If line 1 is out of service and line 2 trips, volts would not be detected by an ADT relay at the remote end of line 2. In this case reclosure of line 2 would not occur.

8.4.2 Design Requirements

Design requirements are summarised in Section 8.5.

8.4.2.1 Distribution Main Protection System

The main protection system shall comprise one of the following:

1) At new sites with LV switchboards, the circuit breakers are within the busbar operating zone. They are therefore protected by the busbar main protection system.

2) At existing sites with outdoor switchgear and no busbar protection, the transformer LV protection system provides the main protection system.

8.4.2.2 Distribution Backup Protection System

The backup protection system shall comprise one the following:

1) At new sites with LV switchboards the transformer LV protection system provides the second protection system.

2) At sites with outdoor switchgear the transformer HV protection system provides the second protection system.

8.4.2.3 Transmission Main Protection System

Circuit breakers do not have their own dedicated main protection system. Instead they are protected by the main protection systems of other circuits. An example is the circuit breakers connected to a busbar are protected by the busbar main protection system.

8.4.2.4 Transmission Backup Protection System

Western Power's preference is for duplicated circuit breaker failure schemes at all transmission voltages to:

1) Meet local total fault clearance time requirement

2) Allow the system to be reconfigured in the future without affecting the backup protection system

3) Minimise risk of blacking out a terminal station for a remote backup operation.

8.4.2.5 Local and Remote Control

The following must be incorporated in the local and remote control design of the circuit breaker:

1) There shall be a facility to open and close circuit breakers from the following locations:

    a) Locally on the circuit breaker

    b) Remotely from the relay panel

    c) Remotely from the East Perth Control Centre (EPCC). Preference is for this remote open and close to be via the protection relay.

2) Both remote open and close facilities must be disabled when the circuit breaker is in the local position. This is usually done by:

    a) A local / remote switch within the circuit breaker

b) Removing the trip and close isolation links.

3) The local close must be disabled when the circuit breaker is connected to the system. This is usually done with disconnector auxiliary switches forming an interlock in the local supply circuit.

4) The automatic reclose function must be disabled when the circuit breaker is in the local position. This is usually done by removing the close isolation link. If available, a contact on the local / remote switch is used to disable automatic reclose.

5) Historically the DC supply for both local and remote control of the circuit breaker is from:

   a) Battery 1 for HV circuits in zone substations

   b) Battery 2 for LV switchboard circuits

   c) Battery 2 in terminal stations

   The majority of brownfield sites follow this design.

6) At green field sites the DC supply for both local and remote control of the circuit breaker is from battery 1 for both zone substations and terminal stations.

8.4.2.6 Check Synchronism

When check synchronism (sync check) is required, the following close signals are conditioned by sync check:

1) Delayed automatic reclose (DAR)

2) High speed single pole automatic reclose (HSSPAR)

3) Remote close from protection panel and EPCC

The following are design requirements for sync check [57].

8.4.2.6.1 Sync Check Close

Sync check close is the local close signal to the circuit breaker that must be conditioned by the sync check function.

8.4.2.6.2 Sync Check Enable

Sync check enable ensures that voltage conditions have been met. This is accomplished by checking that the external interlocking is satisfied. The sync check interlocking must:

1) Include an MCB auxiliary contact from each VT providing a synchronism voltage. A faulty VT providing no volts to the relay could be interpreted as a dead line / live bus or dead bus / live line situation. Under these conditions an unsynchronised close could occur. Including the MCB auxiliary contact helps to prevent closure when a VT is faulty.

2) The following disconnector auxiliary contacts are included in the synch check enable interlock:

   a) All disconnectors between the VTs used for the sync check.

   b) The disconnectors on the system side of the VTs.

[58] Technical Rules clause 3.3.6

This is to ensure that the voltages being checked are present at the circuit breaker. Including these auxiliary contacts also ensures an operator cannot close a disconnector on two out of sync systems.

3) Not include circuit breaker auxiliary contacts. In a check sync design there are two types of circuit breakers.

    a) The circuit breaker undergoing check sync

    b) The circuit breaker not being checked. This circuit breaker is associated with the line not being closed which supplies one of the voltages being compared.

    Including auxiliary contacts from these circuit breakers prevents closing when either of the circuit breakers is open. This prevents initial energising of a substation where all circuit breakers are open.

When there are three lines connected to a busbar the sync check enable interlocking can become complex. In these cases a busbar VT is required.

8.4.2.6.2.1 Functionality

Generally the check synchronisation function must allow closing of the circuit breaker under the following conditions:

1) Dead line and live bus

2) Dead line and dead bus

3) Live line and live bus in synchronism

4) Live line and dead bus

8.4.2.6.2.2 Site Specific Conditions

1) In addition to sync check the line circuit breaker connecting a generator can be prevented from closing out of sync by:

    a) Preventing closing of the line circuit breaker for a live line condition.

    b) Requiring a 'close enable' signal to be sent to the private generator. This signal indicates the line circuit breaker is closed and line energised. The signal is required for the private generator to synchronise and close onto Western Power's system.

        Note that a private generator is required to synchronise to the Western Power system [58]. Under normal conditions the line circuit breaker must therefore always be closed before the generator can be synchronised and closed.

2) Additional disconnector auxiliary contacts may be required depending on site specific conditions (e.g. incomplete 1.5 CB configuration).

8.4.2.6.3 Weld Check

The 'close' contact is the last contact to close and first to open. It is the contact that makes and breaks the trip coil current. If the circuit breaker does not complete is cycle, the cut throat auxiliary contact will not change state and the coil will eventually burn out. This usually results in a short circuit so, even if the close

[58] Technical Rules clause 3.3.6

contact is rated to break the coil current, the close contact would eventually weld shut. The contact is considered welded when:

1) A voltage is detected and
2) The circuit breaker is open and
3) The circuit breaker is not being closed
4) Weld check is no longer required on new designs [59].

8.4.2.6.4 Close Enable

Close enable arms the close contact. Close enable ensures that:

1) The close contact is not welded shut
2) The close contact is the last contact to make and the first contact to break the circuit breaker closing coil current.

Close enable can be implemented in the logic of the relay when the interlocking is performed in the logic.

8.4.2.7 Automatic Reclose

Automatic reclose must be disabled for:

1) The local / remote switch in the local position
2) Circuit breaker failure both locally and remotely

8.4.2.7.1 High Speed Single Pole Automatic Reclose

8.4.2.7.1.1 1.5 Circuit Breaker Terminal stations

1) The high speed single pole automatic reclose (HSSPAR) is performed by the outer circuit breakers of the bay (e.g. 911 and 915). The centre circuit breaker trips 3 pole (e.g. 913).
2) HSSPAR on/off controls are located on the circuit breaker panel and HMI
3) HSSPAR on/off led indication is on both the line and circuit breaker panels and HMI

8.4.2.8 Circuit Breaker Wear Monitoring

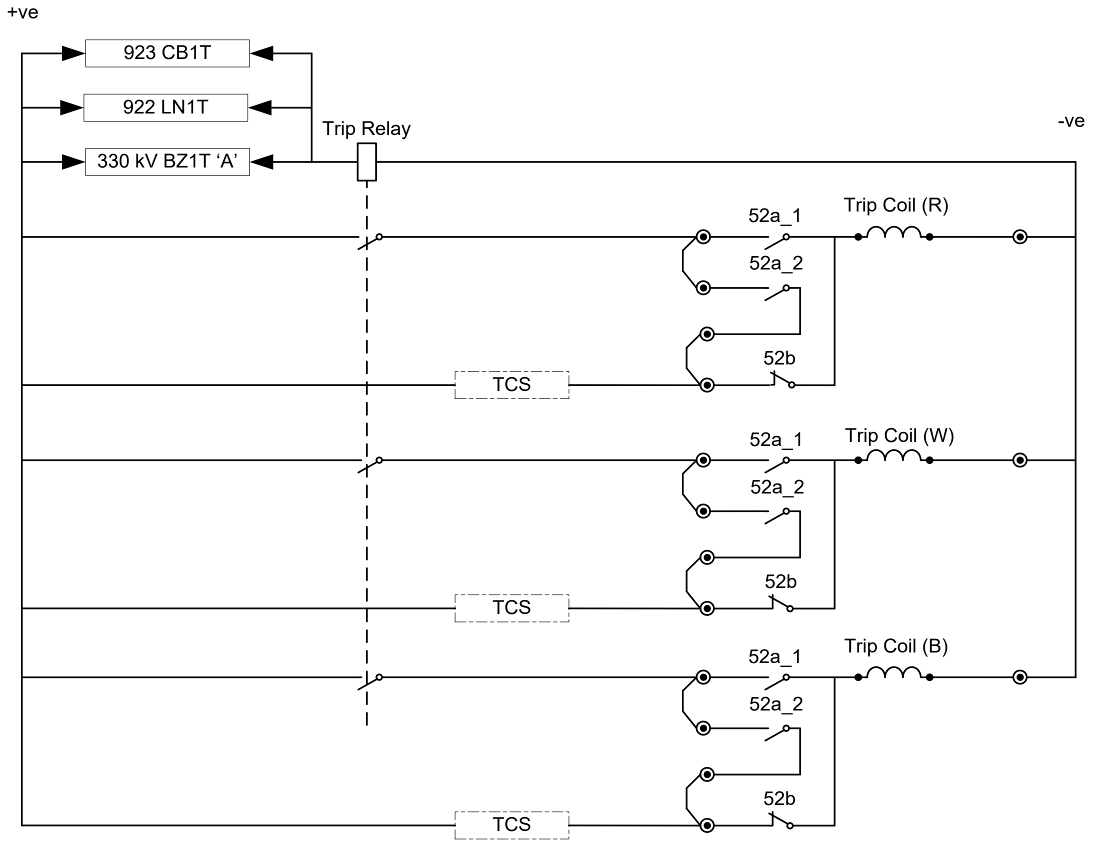
A means of temporarily disabling recording of breaker monitoring information during routine maintenance is required. This preserves accumulated breaker wear information.

8.4.2.9 Replacing a 3 Pole Circuit Breaker with Single Pole Circuit Breaker

Single pole circuit breakers require phase segregated tripping to enable the trip circuit supervision to work correctly. Refer to Engineering Design Instruction – Substation Secondary Systems Design . When replacing a 3 pole circuit breaker with a single pole circuit breaker, use of a trip relay to segregate the trip signals is acceptable. Using a trip relay reduces the inter-panel wiring and rework required on other panels. The trip relay adds 10 milliseconds so the total fault clearance time must be checked to ensure the Technical Rules requirements are still met. Refer to Figure 8.3.

[60] Technical Rules Table 2.11

Figure 8.3 – Single pole circuit breaker with phase segregating trip relay. Circuit breaker shown in closed position.



8.4.3 Standard Functions

8.4.3.1 Check Synchronism

Check synchronism (sync check) ensures that the supplies to both sides of a circuit breaker are synchronised before allowing it to be closed. The sync check relay performs the following checks:

1) The voltage magnitudes on either side of the circuit breaker must be within tolerance. Closure must be prevented for under voltage or for large voltage differences. Typical settings are:

    a) Dead line / bus = 25 V secondary (ph - e). A voltage level of 25 V or less signifies that the line or bus is dead. This setting have been increased to avoid unnecessary blocking of the dead line / bus situation.

    b) Minimum volts for sync check = 0.8 per unit. This setting is below the minimum transmission system voltage of 0.9 pu.

    c) Maximum volts for sync check = 1.2 per unit. This setting is above the maximum transmission system voltage of 1.1 per unit.

    d) Maximum voltage difference is typically the difference between the maximum and minimum voltages or 0.4 per unit.

2) The phase angle difference of the voltages on either side of the circuit breaker must be within tolerance. Transmission planning specifies the voltage angle difference.

3) The frequency difference of the voltages on either side of the circuit breaker must be within tolerance. A setting of 0.01 Hz has been used successfully in the past.

8.4.3.2 Circuit Breaker Failure

The purpose of the circuit breaker failure (CB Fail) function is to clear a fault when tripping a circuit breaker fails to clear its contribution to a fault. The two most common situations which cause a circuit breaker fail are:

1) Failure of a protection scheme to detect a small zone fault

2) A mechanical failure of the circuit breaker

Upon detection of a circuit breaker fail condition, the CB Fail function initiates tripping of other circuit breakers to isolate sources supplying fault current. These may include transformers, bus sections, lines and generation circuit breakers.

CB Fail was previously called local backup (LBU). While CB Fail is a type of local backup protection, there are other types of local backup.

Circuit breaker failure is performed by both the current check and the auxiliary contact methods. If auxiliary contacts are not available and there is no specific requirement for the auxiliary contact method, the current check method alone is sufficient. The auxiliary contact method is typically required on generation circuits.

8.4.3.2.1 Current Check Method

When the circuit breaker trip signal is sent to the circuit breaker the CB Fail timer is started (CB Fail Initiate). Determination of a circuit breaker fail condition is based on detectable current flowing after the timer is timed out. The current check method is suitable for small zone fault detection.

8.4.3.2.2 Auxiliary Contact Method

When the circuit breaker trip signal is sent to the circuit breaker the CB Fail timer is started (CB Fail Initiate). Determination of a circuit breaker fail condition is based the auxiliary contact not changing state before the timer has timed out. Advantages and disadvantages of the auxiliary contact method include:

Advantages:

1) This scheme is not dependent on fault current therefore it works with low level faults (e.g. incipient faults in transformers).

Disadvantages:

1) It does not measure fault current therefore it is not suitable for small zone fault protection.

2) It does not provide for the case where the CB mechanism opens (and therefore also the auxiliary switch) but fails to clear the fault. This could be due either to a failed CB operating rod or failed dielectric quenching medium.

Both a normally open and a normally closed auxiliary contact are used in the CB Fail logic to overcome reliability issues with auxiliary contacts. These contacts are used to condition the auxiliary contact CB Fail trip as follows:

1) CB Fail trip is allowed if both auxiliary contacts change state correctly.

2) CB Fail trip is allowed if both auxiliary contacts do not change state correctly and the current check method is not in use. Other means of clearing the fault should have operated before the CB Fail timer has timed out. Incorrect operation of auxiliary contacts indicates a possible mechanical problem with the circuit breaker.

3) CB Fail trip is not allowed if both auxiliary contacts do not change state correctly and the current check method is also in use. The current check CB Fail method is relied on to clear the fault.

Table 8.1 summarises the normally open / normally closed contact logic.

Table 8.1 – Auxiliary Contact Method CB Fail Trip

Current Check Method in Use	Contacts Operate Correctly	Contacts Operate Incorrectly
Yes	CB Fail Trip Allowed	CB Fail Trip Not Allowed
No	CB Fail Trip Allowed	CB Fail Trip Allowed

8.4.3.2.3 *Functional Requirements*

The operation of the CB Fail function must meet the following requirements:

1) Be sensitive enough to detect all faults for which CB Fail operation is required
2) Time delayed on pickup enough to allow for the expected normal clearance by the associated circuit breaker

8.4.3.2.4 *Operation*

The CB Fail operation is outlined below:

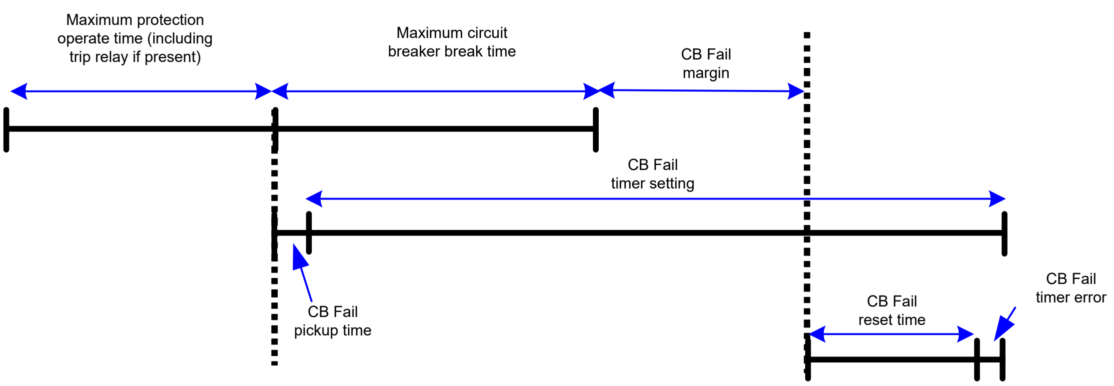
1) Commence timing when a protective function operates with the intention of tripping the nominated circuit breaker
2) Cease timing if the fault current is interrupted or the protection function resets
3) Trip other circuit breakers if the time delay on pickup expires and fault current is still flowing or the auxiliary contacts have not changed state.
4) Provide indication of the failed circuit breaker

8.4.3.2.5 *CB Fail Settings*

The settings are selected to meet the following requirements:

1) CB Fail pickup determined by the following limits:
   a) Lower limit: The pickup is set as sensitive as the protection relay will permit.
   b) Upper limit: Must meet Western Power's sensitivity requirements.
2) CB Fail timer
   a) Setting: The purpose of the CB Fail timer setting is to allow sufficient time for the associated circuit breaker to clear a fault. The required delay can be determined by considering Figure 8.4 below:

Figure 8.4 – Circuit Breaker Failure Timer Setting



   b) From the Figure 8.4, it is seen that the circuit breaker failure timer setting is the:
      i) Sum of the:

ii) Circuit breaker maximum breaking time

iii) Circuit breaker failure margin (40 ms)

iv) Circuit breaker failure reset time

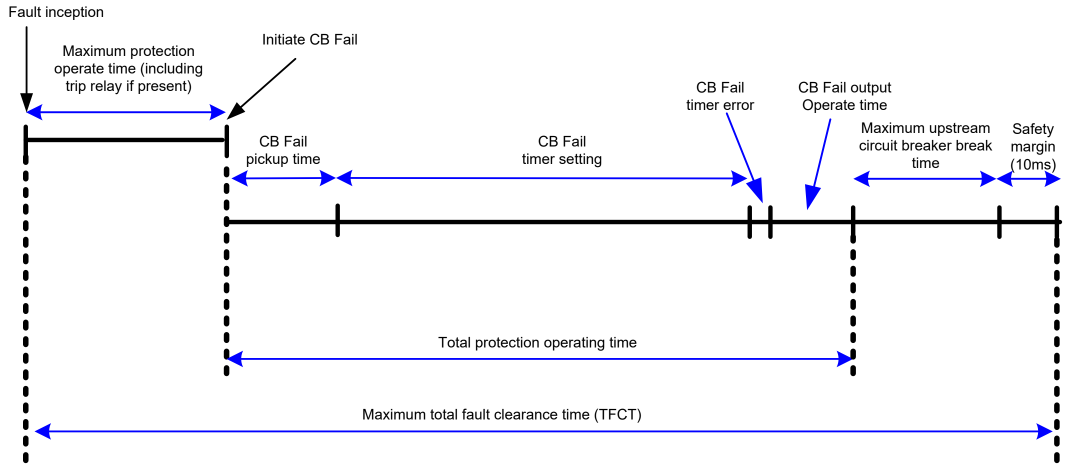
v) Circuit breaker failure timer error

Less the

vi) Circuit breaker failure pickup time

c) Maximum total fault clearance time (TFCT): For a given circuit breaker failure timer setting, the maximum circuit breaker failure total fault clearance time (TFCT) must be evaluated. This is to ensure that the Technical Rules maximum fault clearance time requirement is met [60]. The TFCT can be evaluated by considering Figure 8.5 below:

Figure 8.5 – Circuit Breaker Failure Maximum Total Fault Clearance Time



d) From Figure 8.5 it is seen that the maximum TFCT for a circuit breaker failure is the sum of the:

i) Maximum protection operating time

ii) CB Fail pickup time

iii) CB Fail timer setting

iv) CB Fail timer error

v) CB Fail trip contact time

vi) CB Fail trip relay time

vii) Upstream circuit breaker maximum breaking time (including arc clearance)

viii) Safety Margin (10 ms)

[60] Technical Rules Table 2.11

8.4.3.3 Local and Remote Metering

Refer to Engineering Design Instruction – Substation Secondary Systems Design for local Metering requirements.

8.4.3.4 Circuit Breaker Wear Monitoring

The purpose of the circuit breaker wear function is to assist in the scheduling of circuit breaker maintenance.

Settings are chosen to allow the relay to calculate and accumulate circuit breaker wear information during each circuit breaker opening action.

8.4.3.5 Trip Circuit Supervision

The purpose of trip circuit supervision (TCS) is to supervise the integrity of the circuit breaker trip coil.

Refer to Engineering Design Instruction – Substation Secondary Systems Design for a detailed description of TCS.

8.4.3.6 Dynamic Disturbance Recorder

The dynamic disturbance recorder (DDR) must be configured so that the recorder captures the:

1) Pre fault waveforms.
2) Post fault waveforms which include circuit breaker failure operations.
3) Post fault waveforms which include clearance by downstream devices within the main protection system operating zone.

8.4.3.7 Sequence of Events Recorder

The sequence of events recorder (SER) monitors what occurs within the relay during both normal operation and faults. When the SER is triggered, a record is created of these events. A protection trip must trigger the SER.

To simplify the event record and minimise the chance of the relay failing, the following guidelines must be followed when choosing what is to appear in the SER:

1) Do not include word bit outputs of directional elements
2) Do not include word bits that may change state frequently under normal conditions, or near the edge of such conditions

8.4.3.8 Time Synchronisation

The protection relays must be configured to receive the Irig B time code or the SNTP time signal when available. The Irig B clock and the SNTP server provide accurate time stamping for fault events. Irig B is more accurate and preferred when no additional wiring is required.

Irig B is standard for all DNP relays. Irig B is standard on IEC61850 relays when additional wiring is not required (e.g. zone substation HV relays). When additional wiring is required SNTP is used (e.g. zone substation LV relays).

8.4.3.9 Defective Alarms

Protection defective means the protection scheme is defective. At DNP sites this is hardwired from the IED to the RTU and means that the IED is defective. At IEC61850 sites it includes failure of the IEC61850 signalling.

Device defective means that the hardware is defective. Examples include IEDs, controllers and gateways.

Defective alarms use normally open contacts when hardwired.

8.4.3.10 Site Specific Functions

8.4.3.10.1 Automatic Reclose

8.4.3.10.2 Delayed Automatic Reclose

Typical settings are of the order of:

1) Dead time = 5 – 15 seconds

2) Reclaim time = 5 – 35 seconds

8.4.3.10.3 High Speed Single Pole Automatic Reclose

Typical settings are of the order of:

1) Dead time = 400 ms – 690 ms. The dead time must allow the circuit breaker to reclose before pole discrepancy timer operates. If an adaptive dead time is used, it must be used at the end with the strongest source.

2) Reclaim time = 500 ms – 16 seconds

8.5 Appendix A – Circuit Breaker Design Requirements

Functions		Operation						Indication					
Function Name	**ANSI**	**Initiation**		**Selection**		**Resetting**		**Operation**		**Selection**		**Resetting**	
		A/R	**CB Fail**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**Self**
Circuit breaker failure	52					Latched		Yes	Yes			Yes	
Local metering	HMI												
Remote metering	77												
Delayed automatic reclose	79			Yes	Yes	Self		Yes	Yes	Yes	Yes		Yes
High speed single pole automatic reclose	79			Yes	Yes	Self		Yes	Yes	Yes	Yes		Yes
VT failure	47					Self		Yes	Yes				Yes
Circuit breaker wear monitoring	94.1			Yes						Yes			
Trip circuit supervision	TCM					Self		Yes	Yes				Yes
Check synchronisation	3					Self		Yes	Yes				Yes
Dynamic disturbance recorder	DDR												
Sequence of events recorder	SER												
Time synchronism defective	CLK								Yes				
Protection defective						Self		Yes	Yes				Yes
Device defective						Self		Yes	Yes				Yes
Circuit breaker mechanism defective		Block				Self		Yes	Yes				Yes
Synchronism check disable				No	Yes		Yes			Yes	Yes		

Note: Grey areas signify 'No' or 'Not Applicable'

Note: Relay Resetting includes both contact and word bit resetting

9 Feeder Protection

9.1 Introduction

The purposes of this section are to:

1) Define at a high level the functional requirements for distribution feeder protection in a Western Power zone substation
2) Capture information which explains the reasoning behind the distribution feeder protection design and settings

9.2 Scope

This section applies to distribution feeder circuits within a Western Power zone substation at voltages 33 kV and below. Protection of distribution feeders downstream from the zone substation is not part of this section.

9.3 Functional Requirements

The functional requirements for the feeder protection systems are:

1) Detect and clear faults in the feeder protection operating zone. Refer to Section 9.7.
2) Detect and clear faults within times specified by the Technical Rules.
3) Coordinate with upstream and downstream protection systems.
4) Provide backup for downstream protection systems.
5) Clear faults within the thermal limits of associated primary equipment, including the power transformer.
6) It is not a purpose of the feeder protection systems to provide overload, over voltage or under voltage protection for circuit breakers, transformers or conductors.

9.4 Feeder Protection

9.4.1 Introduction

The primary purpose of the feeder protection system is to minimise danger to the public and loss of supply by clearing faults on the feeder. Other purposes include control and monitoring to facilitate operation of the feeder and to minimise damage to primary equipment.

The feeder protection system must take into account the following system considerations:

1) Type of upstream and downstream protection systems
2) Type of feeder loads (static, PPG, single phase systems)
3) Fault levels
4) Critical fault clearance times
5) Quality of supply

9.4.1.1 Operating Time

Fast protection operating times minimise danger and primary equipment damage. The fastest possible operating time, which provides discrimination when required, should therefore be set.

The main and second feeder protection systems shall, in combination, satisfy all of the following conditions:

1) Achieve the relevant total fault clearance times specified by the Technical Rules [61] and summarised in Table 9.1. These times must only be met for maximum system conditions with the supply from a single zone substation transformer. The times specified in the Technical Rules apply only to local faults. The operating time for faults on the feeder outside of the zone substation is not defined.

2) Achieve critical fault clearance times where specified by the System Analysis and Solutions section [62].

3) Achieve a fault clearance time that does not exceed the thermal rating of the zone substation transformer with the lowest thermal rating. If the zone substation is a rapid response transformer (RRST) site, this requirement includes the RRST. This requirement shall be achieved over the fault level range defined by:

    a) Lower end: 150% of the lowest thermally rated transformer, full load rating

    b) Upper end: The maximum fault level at the feeder CB when fed only by the lowest thermally rated transformer.

    The main and second protection system operating times must not exceed the thermal rating of the feeder conductor. Ensuring this is the responsibility of the distribution planning engineer.

Table 9.1 – Maximum total fault clearance time

Voltage Level	No Circuit Breaker Failure	Circuit Breaker Failure
33 kV and below	1160 ms	1500 ms

For a main protection system failure the total fault clearance time is the same as for a circuit breaker failure.

9.4.2 Design Requirements

Standard functions are provided on all feeder circuits to assist with standardisation of protection design and setting files. Site specific functions are provided at the discretion of the protection design engineer.

It is the responsibility of the protection design engineer to:

1) Liaise with stakeholders to ensure the design meets the stakeholder requirements.

2) Determine which of the site specific functions are required for individual feeders.

3) Determine if an individual feeder application requires additional functions not listed in this section.

4) Verify that standard settings are suitable.

[61] Technical Rules clause 2.9.4(b)
[62] Technical Rules clause 2.9.5(a)

5) The service status of some functions can be controlled from the network operations control centre (NOCC). It is the responsibility of network operations to switch these functions into, or out of service, as required. Examples of

6) Section 9.5 outlines the design requirements for standard functions and site specific functions.

9.4.2.1 Sensitivity

Protection systems must be capable of detecting faults to meet Western Power's sensitivity requirements. Refer to Section 16 – Protection Sensitivity.

9.4.2.2 Residual Current

Preference is given to measuring the residual current of the phase CTs using a separate element in the protection relay. Calculating the residual current by summing the phase vectors is acceptable if measuring is not possible. The reason for this preference is that the range of pickups available in the protection relay is generally higher for measured values.

9.4.2.3 Under Frequency Load Shedding

When possible new feeder circuits shall have the protection relay provide under frequency load shedding (UFLS).

At some older sites the under voltage load shedding (UVLS) scheme trips via a hardwired UFLS scheme. When the UVLS trips into the UFLS scheme before the stage selection it may be necessary to add the feeder to the existing UFLS scheme (e.g. BUH). When the UVLS trips into the UFLS scheme at the UFLS trip relays, the protection relay can perform UFLS (e.g. GTN).

9.4.2.4 Double Cable Terminations

The following applies to distribution feeders with double cable terminations:

1) The feeder circuit's main and second protection systems will protect both cables.

2) Both cables will have independent CT cores providing independent local and remote metering of white phase current. This metering is independent of the main protection system metering.

3) Individual cables will have a fault indicator to distinguish which cable is faulty. Refer to Engineering Design Instruction – Substation Secondary Systems Design .

9.4.2.5 Bush Fire Mitigation

The asset manager will determine if a feeder is in a potential bush fire area. In these site specific cases a relay with a high impedance function (HIZ) capable of detecting and clearing high impedance faults is required.

9.4.2.6 Check Synchronism

If a generator is connected to the distribution system, it is the responsibility of the generator to install check synchronising and island detection functionality on the generating unit circuit breakers. Check synchronising will therefore not be provided on Western Power's feeder circuit breakers [63].

[63] Technical Rules clauses 3.5.2 and 3.6.7.3(b)

9.4.2.7 Distribution Connected Generation

Refer to Section 16 – Protection Sensitivity.

9.4.2.8 Protection Operating Limit

The protection operating limit (POL) is calculated by the protection design engineer and provided to the network operator. The POL gives the network operator an upper boundary to operate the system without causing the protection to operate. The IDMT Overcurrent pickup is used to calculate the POL to ensure that load does not cause a trip (IDMT Earth Fault is not used as load is considered a balanced 3 phase supply). Relays can be grouped according to their errors:

1) Errors are positive. The protection will not operate until the pickup setting is reached. For these relays the POL is calculated by the following formula:

   POL = (IDMT Overcurrent pickup setting x CT ratio)

2) Errors are negative and positive. The relay may operate before the pickup setting is reached. For these relays the POL is calculated by the following formula:

   POL = (IDMT Overcurrent pickup setting – relay errors) x CT ratio

9.4.3 Main Protection System Standard Functions

The following standard functions are provided for all feeder applications.

9.4.3.1 IDMT Overcurrent

The main purpose of the IDMT overcurrent function is to detect and clear 3 phase faults. When negative phase sequence protection is not provided, IDMT overcurrent must also detect and clear phase to phase faults. IDMT Overcurrent may also respond to faults involving heavy unbalance and/or earth faults.

The settings are selected to meet the following requirements:

1) Pickups determined by the following limits:

   a) Lower limit: The lower limit is calculated from:

      i) Pickup specified by the distribution planning engineer. This pickup must be above the maximum anticipated feeder load and grade with downstream protection pickups.

      ii) Allowance for relay errors.

   b) Upper limit: Must meet Western Power's sensitivity requirements. Refer to Section 16 – Protection Sensitivity.

2) Time multiplier setting (TMS) as specified by the distribution planning engineer. The protection design engineer must ensure that:

   a) There is adequate coordination with the transformer protection.

   b) No transformer short circuit ratings are exceeded.

   c) No thermal limits are exceeded when the number of automatic reclose shots on the feeder is considered. Circuit breaker failure during an automatic reclose cycle is not considered due to the:

      i) Low probability of this event

ii) Constraints it would place on the number of automatic reclose shots

iii) Constraints it would place on the feeder time multiplier setting

d) The total fault clearance time is at most 1 second and considers the operating time considerations outlined in section 9.4.1.1 when the fault is:

i) Under maximum system conditions

ii) Supplied from only 1 transformer

iii) Bolted and just outside the substation

A maximum of 1 second is selected to ensure that the fault is cleared within the 2 second thermal rating of the transformer allowing for 1 automatic reclose shot [64].

9.4.3.2 Instantaneous Overcurrent

The purpose of the instantaneous overcurrent function is to detect and clear high current, 3 phase and phase to phase faults. In general, the metropolitan distribution system is earthed via earthing transformers which limit the earth fault levels. The instantaneous overcurrent function will therefore not respond to earth faults.

An instantaneous overcurrent function is required if one, or more, of the following applies:

1) The distribution planning engineer has requested the function. Typically this is to protect sections of under rated conductor.

2) Quality of supply issues. Fast clearance reduces disruptions to customers on adjacent feeders due to voltage depression during the fault.

3) Critical fault clearance times exist and cannot be met by IDMT overcurrent functions.

4) Thermal ratings of equipment within the zone substation might otherwise be exceeded.

9.4.3.3 Transformer Paralleling Overcurrent

The purpose of the transformer paralleling overcurrent (TPO) function is to allow paralleling of transformers without damaging distribution equipment. When transformers are operated in parallel the fault level may exceed the rating of the distribution equipment. The two types of TPO functions are the:

1) Feeder TPO function which has no deliberate time delay. A loss of discrimination with downstream reclosers is considered to be acceptable when transformers are paralleled. The feeder TPO function is comprised of an independent instantaneous overcurrent element.

2) Transformer TPO function is time delayed by 150 ms to allow the feeder TPO to operate first. The transformer TPO element is comprised of an independent definite time overcurrent element. The transformer TPO is provided by the transformer LV protection scheme.

At 22 kV a standard pickup setting of 3 kA is set for the feeder TPO.

[64] AS60076.5 2012 clause 4.1.3

9.4.3.4 Negative Phase Sequence

The purpose of negative phase sequence (NPS) function is to detect and clear unbalanced fault conditions which do not necessarily involve earth. The NPS elements do not respond to balanced load so they can be set more sensitively than three phase overcurrent elements.

The NPS function is a hybrid combination of an inverse curve and a definite time function set to 2 seconds. [65] Two seconds is therefore the fastest the feeder NPS will clear a fault. Depending on how the distribution network is configured, it is possible for a non directional NPS element to detect faults on adjacent feeders. The 2 second operating time allows the protection on the faulted feeder time to clear the fault. The 2 second operating time is considered acceptable at the lower faults levels cleared by NPS.

The settings are selected to meet the following requirements:

1) Pickups determined by the following limits:

    a) Lower limit: The lower limit is calculated from the first recloser settings:

        i) The feeder protection must grade with the NPS of the first recloser. Currently NPS is not typically set on the feeder reclosers.

        ii) When NPS is not set in the first recloser, the feeder protection must grade with the over current setting. This is typically 280 A [66] in the metropolitan area. This is contingent on the upper limit of the pickup not being exceeded.

        iii) Allowance for relay errors.

    b) Upper limit: Must meet Western Power's sensitivity requirements. Refer to Section 16 – Protection Sensitivity.

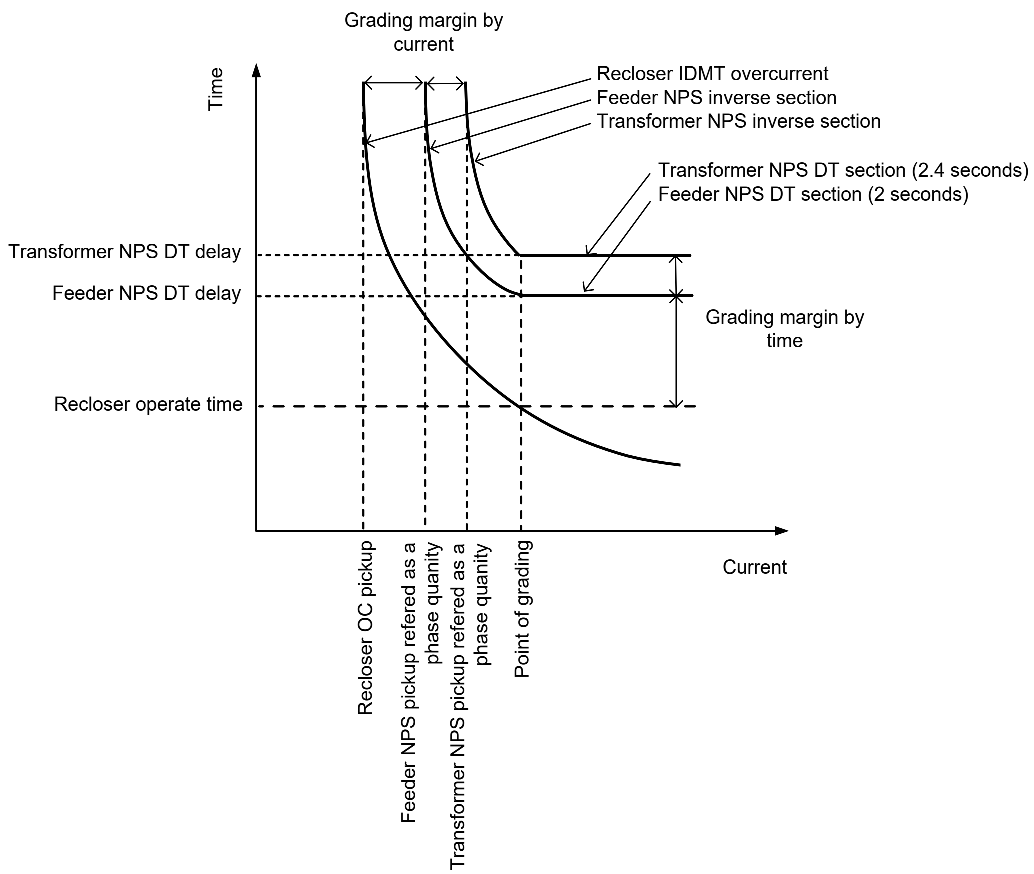
       The expected maximum load shall be distributed along the feeder in the fault analysis study.

2) The NPS hybrid must grade with the recloser IDMT overcurrent at the current corresponding to the point where the NPS hybrid curve's definite time and inverse curve intersect. This assures grading between the two characteristics at all fault levels. The definite time delay of the hybrid curve must therefore be specified before computing the time multiplier of the hybrid's inverse curve. The standard definite time delay for the feeder NPS is 2 seconds. Refer to Figure 9.1.

[65] The present day NPS hybrid function has evolved from early NPS functions which were directional IDMT. In early applications, directionality was used to avoid tripping healthy *feeders supply*ing NPS contributions to an adjacent, faulted *feeder*. To avoid loss of discrimination for under VT failure conditions, elements and logic were employed to convert the NPS to a non-directional function having a 2 second definite time delay for *VT* failure. More recently, the complexity of the NPS hybrid function was reduced by removal of the logic for VT failure, resulting in the present day NPS hybrid function.

[67] At some older sites the earth fault pickup is 80 A. This results from a CT ratio of 800 /1 with a relay that has a minimum 10% setting. Modern relays have a much lower minimum pickup so a 60 A pickup should not be a problem.

Figure 9.1 – Negative Phase Sequence Grading



9.4.3.5 *IDMT Earth Fault*

The purpose of the IDMT earth fault function is to detect and clear faults involving earth. Settings are selected to meet the following requirements:

1) Pickups are determined by the following limits:

   a) Lower limit: The lower limit is calculated from:

      i) The distribution planning engineer specifies the IDMT earth fault pickup specification.

   b) Upper limit: Must meet Western Power's sensitivity requirements. Refer to Section 16 – Protection Sensitivity.

      Because of relay plug setting limitations on older electromechanical relays, the upper limit has historically been set not to exceed 60 A [67]. The 60 A limit provides a basis for the 72 A transformer LV IDMT earth fault pickup and the 90 A stand-by earth fault (SBEF) pickup.

2) Time multiplier setting (TMS) is specified by the distribution planning engineer. The protection design engineer must ensure that:

   a) There is adequate coordination with the transformer protection

[67] At some older sites the earth fault pickup is 80 A. This results from a CT ratio of 800 /1 with a relay that has a minimum 10% setting. Modern relays have a much lower minimum pickup so a 60 A pickup should not be a problem.

b) No short circuit ratings are exceeded

c) After considering the number of automatic reclose shots on the feeder, there are no thermal limits exceeded. This includes, but is not limited to, the power transformer and earthing transformer thermal limits.

d) The total fault clearance time is at most 1 second and considers the operating time considerations outlined in section 9.4.1.1 when the fault is:

   i) Under maximum system conditions

   ii) Supplied from only 1 transformer

   iii) Bolted and just outside the substation

At many rural zone substations, the transformer has star – delta – star windings with the LV star point solidly earthed. This ensures enough earth fault current to allow the transformer earth fault protection to operate. These zone substations may also have single phase systems which can cause unbalance. If the feeder loads are not balanced, the unbalance current will be detected by the transformer earth fault relay. It is important to ensure adequate grading between the transformer and feeder IDMT earth fault protection schemes taking this additional unbalance current into account.

9.4.3.6 Sensitive Earth Fault

The purpose of the sensitive earth fault (SEF) function is to detect and clear very high resistance, low level fault conditions involving earth.

The distribution system is composed of feeders originating at zone substations and feeding radial networks of 33, 22, 11 or 6.6 kV / 415 V delta star transformers. Earth reference is provided at the originating substation by either earthing transformers or solid earthing. This arrangement makes possible the application of sensitive earth fault protection to cover the distribution network. SEF need only be set above zero sequence charging currents, or as necessary to provide coordination with other distribution protection devices. SEF does not respond to zero sequence currents associated with the 415 V networks because the delta star transformers isolate these currents.

The settings are selected to meet the following requirements:

1) The distribution planning engineer specifies the pickup and time delay. The protection design engineer must ensure that the settings take into account the relay and timer errors.

2) The distribution planning engineer will advise the protection design engineer if SEF is normally in service or out of service by the network operations control centre (NOCC). If SEF is not normally to be selected into service by NOCC, standard settings of 9 amp pickup and 11 second time delay are applied. The setting order and grading sheet must state that this function is to be normally selected out of service by NOCC. This arrangement allows NOCC to bring SEF into service if a need arises.

9.4.3.7 Switch On To Fault

The purpose of the switch on to fault (SOTF) function is to detect and clear closure of the associated circuit breaker onto a set of working earths applied to the feeder at, or very near, the zone substation.

SOTF comprises a single phase instantaneous overcurrent element and associated logic. SOTF can be summarised as follows:

1) The SOTF function shall be “armed” when the circuit breaker has been opened and the standard SOTF enable time of 60 seconds has elapsed. The circuit breaker is determined to be open when:
    a) Current is below a set level in all phases and
    b) The circuit breaker auxiliary contacts indicate that the circuit breaker is open
2) The SOTF function shall be "disarmed" when the circuit breaker has been closed and the standard SOTF duration time of 0.6 seconds has elapsed. The circuit breaker is determined to be closed when:
    a) Current is above a set level in at least one phase or
    b) The circuit breaker auxiliary contacts indicate that the circuit breaker is closed
3) SOTF shall be voltage restrained when a VT is available. Restraint for load inrush conditions and VT failure is provided by a voltage element. Restraint for VT failure is provided by logic. Refer to section 9.4.3.13.

9.4.3.7.1 SOTF Settings

The SOTF settings are selected to meet the following requirements:

1) Pickups are determined by the following limits:

   a) The lower limit of the setting is calculated from:

      i) Overcurrent pickup

      ii) A margin. The SOTF margin ensures that the pickup of SOTF is above the maximum intended steady state feeder load. This avoids the sequential event buffer being filled with uninteresting changes. The SOTF margin is normally set to 130% of the feeder load.

      iii) Relay errors.

      In practice, a small setting may be acceptable, if a very secure restraint for cold load inrush and VT failure conditions is possible [68].

   b) Upper limit: Must meet Western Power's sensitivity requirements. Refer to Section 16 – Protection Sensitivity.

2) Phase under voltage pickup. All phase voltages must be below this setting for the phase under voltage function to pickup. The phase under voltage pickup must be:

   a) Above a lower boundary just above zero. The lower the pickup is set, the less effective the SOTF function will be. If the pickup is set close to zero, only earths placed close to the bus bar will cause SOTF to operate.

   b) Below an upper boundary defined by the voltage sag caused by energising a heavily loaded, healthy feeder. Analysis of load inrush waveforms recorded on fully loaded feeders shows voltage sag down to 70% of nominal.

   c) A standard setting of 40% of the nominal operating voltage has been used with success. This setting:

      i) Permits working earths within the radius of interest to be detected

      ii) Differentiates between load inrush current and fault current caused by working earths

9.4.3.8 Circuit Breaker Failure

The purpose of the circuit breaker failure (CB Fail) function is to detect when the tripping of a circuit breaker fails to clear its contribution to a fault. This can be caused either by the circuit breaker failing to open or by a small zone fault.

CB Fail was previously called local backup (LBU). While CB Fail is a type of local backup protection, there are other types of local backup.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of CB Fail.

[68] Historically when *voltage* restraint was not used a SOTF allowance factor of 3 was used to allow for cold load inrush. A factor up to 6 would have been used if loads were known to draw large inrushes. Unrestrained SOTF operations have been experienced at settings based on 150% of maximum load.

9.4.3.9 Under Frequency Load Shedding

The purpose of the under frequency load shedding (UFLS) function is to rapidly shed load when system frequency declines from normal. UFLS attempts to restore balance between load and available generation. The Technical Rules specify five UFLS stages [69]. Refer to Section 13 – Under Frequency Load Shedding for more information.

9.4.3.10 Local Metering

Refer to Engineering Design Instruction – Substation Secondary Systems Design for local Metering requirements.

9.4.3.11 Remote Metering

Remote Metering of all 3 phase and neutral currents is required on all single wire earth return (SWER) feeders. This is to allow the distribution engineer to monitor out of balance conditions. Three phase and neutral currents are monitored on all other feeders for standardisation. Refer Engineering Design Instruction – Substation Secondary Systems Design for remote Metering requirements.

9.4.3.12 Delayed Automatic Reclose

The purpose of the delayed automatic reclose (DAR) function is to automatically restore supply following a transient fault.

Delayed automatic reclose must be taken out of service when:

1) The operator selects the local / remote switch on the circuit breaker to the local position
2) The circuit breaker mechanism is defective

The distribution planning engineer will advise the protection design engineer of the delayed automatic reclose settings and if it is normally into or out of service by NOCC. If delayed automatic reclose is not required it is still provided with standard settings. The setting order and grading sheet must state that this function is normally selected out of service by NOCC. This arrangement allows NOCC to bring delayed automatic reclose into service if a need arises.

To reduce stress on the primary equipment, DAR is normally not initiated by an instantaneous overcurrent operation. At remote sites with low fault levels, it may be acceptable to initiate DAR by instantaneous overcurrent to improve reliability.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of DAR.

9.4.3.13 VT Failure

The purpose of the VT fail function is to distinguish between two distinct conditions. Both of these conditions result in a disturbance or loss of secondary volts from the VTs to the relay. The two conditions are:

1) Primary system fault conditions such as:
   a) Phase to earth faults
   b) Phase to phase faults

[69] Technical Rules clause 2.4.1

c) Three phase faults

The protection relay must determine that a primary fault exists and that there is not a problem with the VT or secondary wiring. The protection relay must not declare VT failure, or block the operation of voltage restrained functions.

2) Non primary system fault conditions such as:

a) VT primary isolated by primary switching or primary fuse operation

b) VT secondary disturbed by secondary fuse, or MCB operation

c) Secondary wiring interference

d) Disturbance at the test links

e) Secondary wiring fault

The protection relay must determine that a problem with the VT or secondary wiring exists and that there is not a primary fault. The protection relay must declare VT failure condition. The protection relay may need to block the operation of protection functions that are restrained by voltage.

9.4.3.13.1 Alarming

The VT is used for UFLS, SOTF and metering. It is therefore important to alarm for a VT failure. The protection relay is required to raise a VT fail alarm when:

1) No primary system fault exists and

2) A secondary system fault does exist

9.4.3.14 Circuit Breaker Wear Monitoring

The purpose of the circuit breaker wear function is to assist in the scheduling of circuit breaker maintenance.

Settings are chosen to allow the relay to calculate and accumulate circuit breaker wear information during each circuit breaker opening action.

It is important to preserve accumulated breaker monitoring information during routine maintenance. Therefore it is a requirement that maintenance staff be provided with a means of temporarily disabling the recording of such data.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of circuit breaker wear monitoring.

9.4.3.15 Trip Circuit Supervision

The purpose of the trip circuit supervision (TCS) function is to supervise the integrity of the circuit breaker trip coil when the circuit breaker is in either the open or closed state. TCS also supervises the integrity of some of the associated secondary wiring.

Refer to Engineering Design Instruction – Substation Secondary Systems Design for a detailed description of TCS.

9.4.3.16 Dynamic Disturbance Recorder

The dynamic disturbance recorder (DDR) must be configured so that the oscillography captures the:

1) Pre fault waveforms.
2) Post fault waveforms which include circuit breaker failure operations.
3) Post fault waveforms which include clearance by downstream devices within the main protection system operating zone.

9.4.3.17 Sequence of Events Recorder

The sequence of events recorder (SER) monitors what occurs within the relay during both normal operation and faults. When the SER is triggered, a record is created of these events. A protection trip must trigger the SER.

To simplify the event record and minimise the chance of the relay failing, the following guidelines must be followed when choosing what is to appear in the SER:

Do not include word bit outputs of directional elements

Do not include word bits that may change state frequently under normal conditions, or near the edge of such conditions

9.4.3.18 Time Synchronisation

The protection relays must be configured to receive the Irig B time code or the SNTP time signal when available. The Irig B clock and the SNTP server provide accurate time stamping for fault events. Irig B is more accurate and preferred when no additional wiring is required.

Irig B is standard for all DNP relays. Irig B is standard on IEC61850 relays when additional wiring is not required (e.g. zone substation HV relays). When additional wiring is required SNTP is used (e.g. zone substation LV relays).

9.4.3.19 Defective Alarms

Protection defective means the protection scheme is defective. At DNP sites this is hardwired from the IED to the RTU and means that the IED is defective. At IEC61850 sites it includes failure of the IEC61850 signalling.

Device defective means that the hardware is defective. Examples include IEDs, controllers and gateways.

Defective alarms use normally open contacts when hardwired.

9.4.4 Main Protection System Site Specific Functions

9.4.4.1 Multiple Setting Groups

The purpose of multiple setting groups is to allow the controllers or switching operators to change relay settings when required for different distribution system configurations.

9.4.4.2 High Impedance

The purpose of the high impedance (HIZ) function is to detect arcing faults. These typically arise when a feeder conductor makes contact with a high resistance object or surface such as falling onto dry sand. If an arcing fault is found to be continuous a trip is issued. If an arcing fault is found to be intermittent, an alarm indicating required maintenance is sent to the Network Operations Control Centre (NOCC).

9.4.5 Second Protection System Standard Functions

9.4.5.1 IDMT Overcurrent

The type of second protection system will determine the discrimination requirements with the main protection system. If the second protection system is a:

1) The transformer LV protection system. The second protection system must discriminate with the feeder main protection system.

2) An independent feeder protection scheme tripping into an independent feeder circuit breaker trip coil. When automatic reclose is selected in the main protection system relay, it must be initiated by an operation of the second protection system's IDMT overcurrent. Under this condition the second protection is not required to discriminate with the main protection system. This ensures that automatic reclose is initiated regardless of which protection system operates first.

   If the second protection system does not initiate automatic reclose, it must discriminate with the main protection system. This allows the main protection system to operate first and go through the automatic reclose cycle.

3) An independent feeder protection scheme tripping the busbar circuit breakers. The second protection system must discriminate with the feeder main protection system.

9.4.5.2 Highset Overcurrent

A high set overcurrent function is required if one critical fault clearance times exist and cannot be met by the second protection system IDMT overcurrent functions.

9.4.5.3 Circuit Breaker Failure

Circuit breaker failure is required when the second protection system is an independent feeder protection scheme tripping into an independent circuit breaker trip coil.

9.5 Appendix A – Feeder Design Requirements

Functions		Operation						Indication					
Function Name	**ANSI**	**Initiation**		**Selection**		**Resetting**		**Operation**		**Selection**		**Resetting**	
		A/R	**CB Fail**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**Self**
IDMT Overcurrent	51	Yes	Yes			Self		Yes	Yes			Yes	
Instantaneous overcurrent	50	No*	Yes			Self		Yes	Yes			Yes	
Transformer paralleling overcurrent	50		Yes	Yes	Yes	Self		Yes	Yes	Yes	Yes	Yes	
Negative phase sequence	46	Yes	Yes			Self		Yes	Yes			Yes	
IDMT earth fault	64	Yes	Yes	Yes	Yes	Self		Yes	Yes	Yes	Yes	Yes	
Sensitive earth fault	64		Yes	Yes	Yes	Self		Yes	Yes	Yes	Yes	Yes	
Switch on to fault	SOTF		Yes			Self		Yes	Yes			Yes	
Circuit breaker failure	52					Latched		Yes	Yes			Yes	
UFLS (Circuit stage selection)				Yes	Yes					Yes	Yes		
UFLS (Tripping)	81					Latched	Yes	Yes	Yes			Yes	
Local metering	HMI												
Remote metering	77												
Delayed automatic reclose	79			Yes	Yes	Self		Yes	Yes	Yes	Yes		Yes
VT failure	47							Yes	Yes				Yes
Circuit breaker wear monitoring	94.1			Yes						Yes			
Trip circuit supervision	TCM							Yes	Yes				Yes
Dynamic disturbance recorder	DDR												

Sequence of events recorder	SER												
Time synchronism defective	CLK								Yes				
Protection defective						Self		Yes	Yes				Yes
Device defective						Self		Yes	Yes				Yes
Circuit breaker mechanism defective		Block				Self		Yes	Yes				Yes
Multiple setting groups				Yes	Yes					Yes	Yes		
High impedance	HIZ		Yes		Yes	Self		Yes	Yes		Yes	Yes	

Note: Grey areas signify ‘No’ or ‘Not Applicable’

Note: Relay Resetting includes both contact and word bit resetting

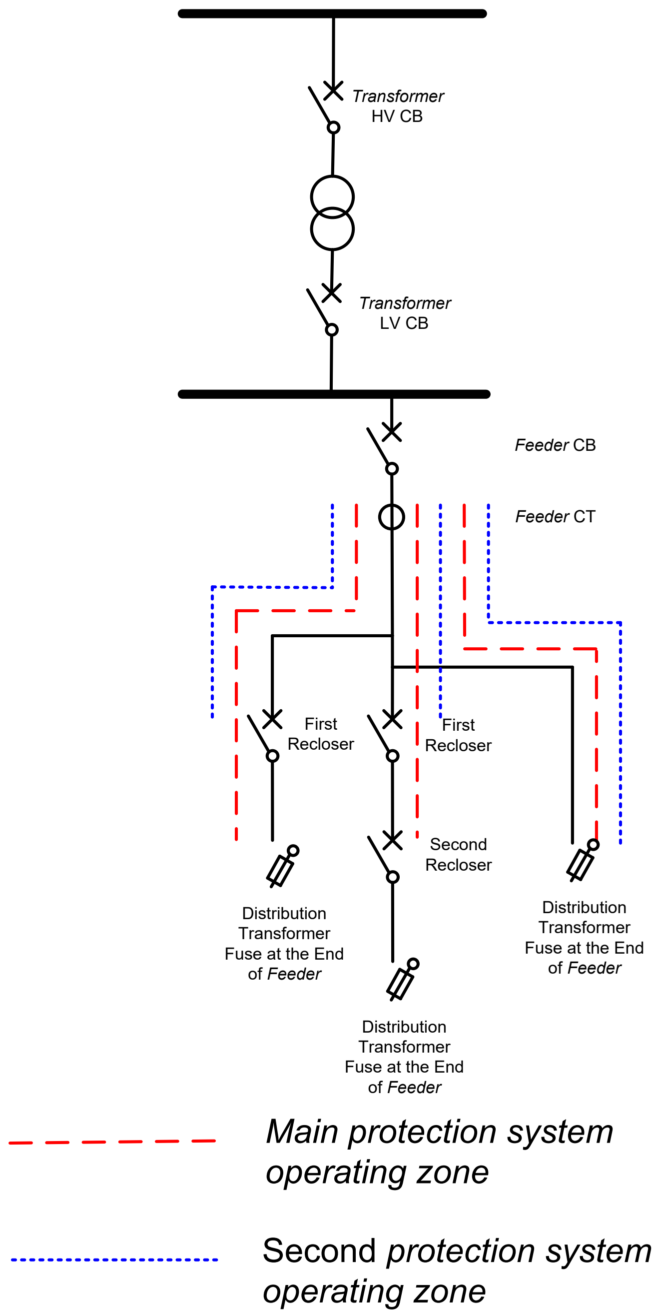
Note: The intent of this table is to provide the protection design and settings engineer with a standard to follow when configuring the main protection relay. It is not intended to capture all local and remote operation and indication which may be present (eg. trip relay and MCB flags)

Note: * At remote sites with low fault levels it may be acceptable to initiate A/R with instantaneous overcurrent. Refer to section 9.4.3.12.

9.6 Appendix B – Roles and Responsibilities

9.7 Appendix C – Operating Zones

The following drawing demonstrates the main protection system and the second protection system operating zones.



10 Capacitor Banks Protection

10.1 Introduction

The purposes of this section are to:

1) Define at a high level the functional requirements for capacitor bank protection in Western Power zone substations and terminal stations

2) Capture information which explains the reasoning behind the capacitor bank protection design and settings

10.2 Scope

This section applies to capacitor bank circuits within a Western Power zone substation or terminal substations.

10.3 Functional Requirements

The functional requirements of capacitor bank protection systems are:

1) Detect and clear faults in the operating zone.

2) Detect and clear faults within times specified by the Technical Rules.

3) Coordinate with upstream protection systems.

4) Clear faults within the thermal limits of associated primary plant.

5) Prevent access to the capacitor bank until it has had time to discharge for a specified time.

6) Send an alarm to EPCC when the capacitor bank requires replacement of individual cans.

10.4 Capacitor Bank Protection

10.4.1 Introduction

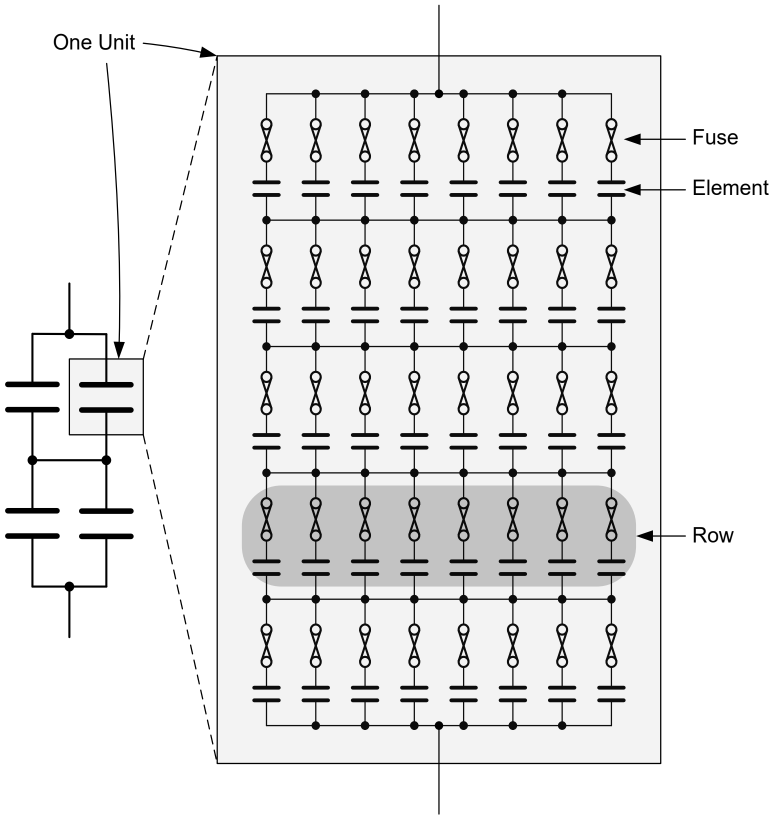
The main purpose of the capacitor bank protection system is to minimise danger to staff and loss of supply by clearing faults on the capacitor bank. Other purposes include control and monitoring to facilitate operation of the capacitor bank.

Capacitor banks can be connected to busbars or transformer tertiary windings.

10.4.1.1 Capacitor Bank Configurations

Shunt capacitor banks are made up of a number of standard units which are also called cans. The units are connected together in series and parallel to give the MVAr and voltage ratings of the bank. The nominal rating of all units in a capacitor bank is the same, however measured values will differ. The manufacturer uses the measured values to assemble the capacitor bank in such a way to minimise the out of balance current. A typical unit contains a number of elements, and these elements may or may not be separately fused. Unfused units are used in high voltage capacitor banks with many units in series and no intermediate interconnections between branches. Figure 10.1 shows a typical unit:

Figure 10.1 – Typical capacitor unit



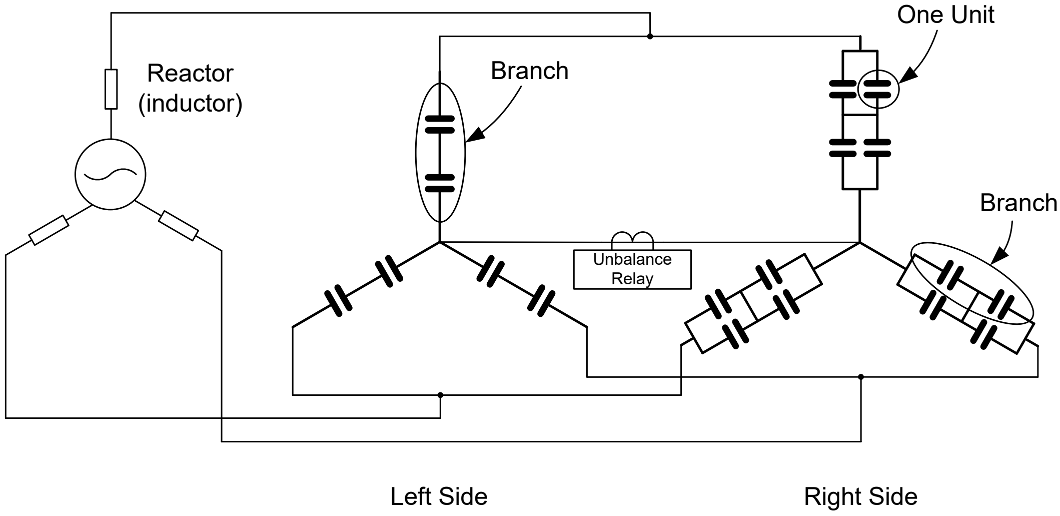
Reactors (inductors) may also be included in each phase of a capacitor bank to limit inrush currents or provide tuning. Reactor ratings are typically on the order of 5% of the capacitor bank rating. These reactors are typically of the air core type. Capacitor banks can be configured as plain banks, detuned banks or filter banks with or without external fuses.

The following examples are standard capacitor banks configurations used in Western Power.

10.4.1.1.1 Star – Star Configuration

Star – star is the current configuration for new capacitor banks at all voltage levels. An advantage of this configuration is that only 1 unbalance CT is required on the neutral connecting the two sides. Figure 10.2 below shows a typical star – star configuration.

Figure 10.2 – Star-star capacitor bank



The capacitor is designed such that:

1) The sum of the phase currents in the left side equals 0
2) The sum of the phase currents in the right side equals 0

Under normal conditions there is no current flowing through the neutral connection. Individual elements fail as the capacitor ages. The reactance of the phase with the failed element changes and an unbalance current develops. The unbalance current is used to detect the element failures.

10.4.1.1.2 Split Phase Star

Split phase star capacitor banks are not currently being installed, but are found throughout the system. A disadvantage of this configuration is that an unbalance CT is required for each phase.

10.4.1.1.3 Split Phase Delta

Split phase delta capacitor banks are not being installed often, but are found throughout the system. A disadvantage of this configuration is that an unbalance CT is required for each phase to phase section.

10.4.1.1.4 Star with VT Protection

Star capacitor banks are not currently being installed, but are found throughout the system. This configuration usually has two units in series per phase with a VT connected in parallel with each. A disadvantage of this configuration is that an unbalance VT is required for each phase.

10.4.2 Design Requirements

Standard functions are provided on all capacitor bank circuits to assist with standardisation of protection design and setting files. Site specific functions are provided at the discretion of the protection design engineer.

Section 10.5 outlines the design requirements for standard functions and site specific functions.

10.4.2.1 Residual Current

Residual current measurement of the phase CTs by summing the phase vectors is acceptable if a neutral element is not available. The neutral element may not be available if it is used to measure the unbalance current.

10.4.2.2 Relay Reset Requirements

A protection scheme that trips for capacitor bank faults shall:

1) Latch
2) Retain its state when powered down

10.4.2.3 Load Shedding

All capacitor bank circuits in zone substations and terminal stations must be incorporated into under frequency and under voltage load shedding schemes. The system operators must have the facility to disable the UFLS or UVLS for individual capacitor banks as required. Refer to Section 13 – Under Frequency Load Shedding and Section 12 – Under Voltage Load Shedding.

10.4.2.4 Interlocks

The protection systems provide all capacitor bank circuits with interlocks to prevent:

1) Earthing of the capacitor bank before the capacitor bank has discharged. Access to the earthing switch is controlled via an earth switch discharge timer within the protection relay. This timer is initiated by the circuit breaker opening and reset by the circuit breaker closing. When the earth switch discharger timer expires, an output of the protection relay energises the earth switch interlock coil. With the interlock coil energised and the capacitor disconnected from the system, the switching operator can earth the capacitor bank.

2) Access to the capacitor bank compound before the capacitor bank has discharged. At new sites, when the capacitor bank earth switch is closed and the circuit breaker open, the capacitor bank compound gate key is released.

   At some older sites an earth switch may not be present. In these cases the state of the circuit breaker controls the time delay and access to the capacitor bank compound.

   At brownfield sites that do not have a protection relay capable of performing the time delay, an external timer is required. Refer to Section 10.9.

3) Closing the capacitor bank circuit breaker
   a) Until after the key allowing access to the capacitor bank compound key is returned to the interlock device
   b) Until after the capacitor bank has discharged

10.4.2.4.1 Indication

Indication to EPCC is required when:

1) The compound gate key has been released.

2) The circuit breaker is ready to be closed. This includes the compound gate key being returned to its capture mechanism.

10.4.2.4.2 Indoor Switchboards

Racking the capacitor bank circuit breaker out of service disconnects the circuit breaker auxiliary contacts from the protection relay. The protection relay interprets the status of the circuit breaker as closed which resets the earth switch discharge timer. An input from circuit breaker service position switch is included in the protection relay logic to avoid resetting the earth switch discharge timer.

10.4.2.5 Point on Wave Switching

Capacitor banks connected at 66 kV & 132 kV have large MVAr ratings which can cause an excessive voltage step when switched. A large voltage step results in excessive circuit breaker contact wear. Point on wave switching of independent circuit breaker poles reduces this voltage step.

10.4.3 Main Protection System Standard Functions

The following standard functions are provided for all capacitor bank applications.

10.4.3.1 IDMT Overcurrent

The purpose of IDMT overcurrent is to clear 3 phase faults. IDMT overcurrent is not deliberately limited to 3 phase fault conditions and may also respond to faults involving heavy unbalance and/or earth faults. IDMT overcurrent protects the capacitor bank against faults which the instantaneous overcurrent protection is unable to detect. IDMT overcurrent is not intended to give protection against overloads due to over voltage or increased frequency.

The settings are selected to meet the following requirements:

1) Pickups determined by the following limits:

    a) Lower limit: The lower limit is calculated from:

        i) The rated current of the capacitor bank.

        ii) An additional margin.

        iii) Allowance for relay errors.

        iv) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements.

    A standard setting of 1.3 times the capacitor rated current at the capacitor rated voltage has been used successfully in the past.

2) A standard time multiplier setting (TMS) of 0.05, in conjunction with a standard inverse IDMT curve, has been used successfully in the past. The protection engineer must ensure that:

    a) There is adequate coordination with the transformer protection

    b) No short circuit ratings are exceeded

    c) The total fault clearance time meets the Technical Rules requirements.

10.4.3.2 Instantaneous Overcurrent

The purpose of instantaneous overcurrent is to clear high current, 3 phase and phase to phase faults. In general, the metropolitan distribution system is earthed via earthing transformers which limit the earth fault levels. The instantaneous overcurrent function will therefore not respond to earth faults.

The instantaneous overcurrent must be set high enough to avoid operation for capacitor inrush currents. The magnitude of the inrush current depends on:

1) System fault level
2) X/R ratio
3) Capacitor rating

Instantaneous overcurrent is generally only capable of detecting faults within the first five to ten percent of the capacitor bank. Faults further into the bank are cleared by the slower overcurrent and unbalance protection. The slower clearance is acceptable because the impedance of the capacitor limits the fault current. The system can withstand slower fault clearance times for these lower fault currents.

Standard settings are:

1) Pickup = 6 x capacitor bank current rating
2) Time delay = 0 seconds

10.4.3.3 IDMT Earth Fault

The purpose of IDMT earth fault is to clear faults involving earth. Settings are selected to meet the following requirements:

1) Pickup:
    a) Lower limit
        i) Because the capacitor bank is not earthed, the IDMT earth fault protection is not required to grade with other protection systems. The pickup can therefore be set to the minimum setting.
    b) Upper limit: Must meet Western Power’s sensitivity requirements.
2) Time multiplier setting (TMS). A standard setting of 0.1 has been used successfully in the past. The relay will operate in a definite minimum time of approximately 200 milliseconds when set to the minimum pickup. This is considered acceptable because:
    a) Complete saturation for 10 cycles is unlikely.
    b) Reactors limit inrush current (in new installations)
    c) A TMS of 0.1 has not resulted in an inrush operation in the past.

10.4.3.4 Capacitor Out of Balance Protection

Capacitor out of balance (COOB) protection detects an unbalance current flowing between the left and right sides of a capacitor bank. The unbalance current results from individual elements failing which changes the impedance of the side with the failed element. The COOB protection alarms and trips the capacitor before over voltages can damage healthy units.

10.4.3.4.1 COOB Alarm Settings

A COOB alarm is included on all capacitor bank installations to provide indication of the presence of faulty units. The COOB alarm level is chosen to alert the operators of the need to disconnect the capacitor bank before a catastrophic failure occurs.

The COOB alarm asserts at the point where one additional element failure results in the capacitor tripping. This setting is considered acceptable for the following reasons:

It is Western Power practice to immediately open a capacitor bank circuit for an unbalance alarm. An investigation is initiated to find the cause of the alarm. There is little risk to the capacitor as it will only be in operation for a few minutes after the alarm has arisen.

The trip setting provides adequate protection should an additional element fail before the capacitor can be manually taken out of service. There is sufficient redundancy in the system to allow a bank to be out of service unexpectedly.

Increased element failure makes detecting the faulty unit easier. This is especially important for asymmetrical capacitor banks where alarm and trip settings are based on the side first reaching the trip threshold. This threshold may be reached after only a few element failures. It is therefore important to allow as many to fail as possible before alarming.

10.4.3.4.2 COOB Trip Settings

The manufacturer’s recommendation for the trip setting is adopted provided that:

1) The voltage across a unit does not exceed 1.1 per unit

2) The voltage across any row within a unit does not exceed 2.0 per unit

10.4.3.5 Circuit Breaker Failure

The purpose of circuit breaker failure (CB Fail) is to clear a fault when tripping a circuit breaker fails to clear its contribution to a fault. Failure to clear the fault contribution can be caused either by the circuit breaker failing to open or by a small zone fault.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of CB Fail.

10.4.3.6 Earth Switch Discharge Timer

Standard setting for the earth switch discharge timer is 10 minutes.

10.4.3.7 Local Metering

Refer to Engineering Design Instruction – Substation Secondary Systems Design for local metering requirements.

10.4.3.8 Remote Metering

Refer to Engineering Design Instruction – Substation Secondary Systems Design for remote metering requirements.

10.4.3.9 VT Failure

The purpose of VT failure is to distinguish between two distinct conditions. Both of these conditions result in a disturbance or loss of secondary volts from the VTs to the relay. The two conditions are:

1) Primary system fault conditions such as:
   a) Phase to earth faults
   b) Phase to phase faults
   c) Three phase faults

   Under these conditions the relay must recognise that a primary fault exists and operate.

2) Non primary system fault conditions such as:
   a) VT primary isolated by primary switching or primary fuse operation
   b) VT secondary disturbed by secondary fuse, or MCB operation
   c) Secondary wiring interference
   d) Disturbance at the test links
   e) Secondary wiring fault

   Under these conditions the relay must recognise that a fault does not exist and not operate. The protection relay may need to take steps to restrain some protection functions.

10.4.3.9.1 Alarming

The VT is used for SOTF restraint so it is important to alarm for a VT failure. The protection relay is required to raise a VT Fail alarm when:

1) No primary system fault exists and
2) A secondary system fault exists

10.4.3.10 Circuit Breaker Wear Monitoring

The purpose of circuit breaker wear monitoring is to assist in the scheduling of circuit breaker maintenance.

Settings are chosen to allow the relay to calculate and accumulate circuit breaker wear information during each circuit breaker opening action. While circuit breaker wear is more dependent on closing for capacitor applications, the opening information is still useful in predicting maintenance requirements.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of circuit breaker wear monitoring.

10.4.3.11 Trip Circuit Supervision

The purpose of trip circuit supervision (TCS) is to supervise the integrity of the circuit breaker trip coil. The trip coil is supervised when in both the open and closed state. TCS also supervises the integrity of some of the associated secondary wiring

Refer to Engineering Design Instruction – Substation Secondary Systems Design for a detailed description of TCS.

10.4.3.12 Dynamic Disturbance Recorder

The dynamic disturbance recorder (DDR) must be configured so that the recorder captures the:

1) Pre fault waveforms.

2) Post fault waveforms which include circuit breaker failure operations.

3) Post fault waveforms which include clearance by downstream devices within the main protection system operating zone.

4) Capacitor bank circuit breakers occasionally have re-strike failures within 200 milliseconds of the circuit breaker opening.

10.4.3.13 Sequence of Events Recorder

The sequence of events recorder (SER) monitors what occurs within the relay during both normal operation and faults. When the SER is triggered, a record is created of these events. A protection trip must trigger the SER.

To simplify the event record and minimise the chance of the relay failing, the following guidelines must be followed when choosing what is to appear in the SER:

1) Do not include word bit outputs of directional elements

2) Do not include word bits that may change state frequently under normal conditions, or near the edge of such conditions

10.4.3.14 Time Synchronisation

The protection relays must be configured to receive the Irig B time code or the SNTP time signal when available. The Irig B clock and the SNTP server provide accurate time stamping for fault events. Irig B is more accurate and preferred when no additional wiring is required.

Irig B is standard for all DNP relays. Irig B is standard on IEC61850 relays when additional wiring is not required (e.g. zone substation HV relays). When additional wiring is required SNTP is used (e.g. zone substation LV relays).

10.4.3.15 Defective Alarms

Protection defective means the protection scheme is defective. At DNP sites this is hardwired from the IED to the RTU and means that the IED is defective. At IEC61850 sites it includes failure of the IEC61850 signalling.

Device defective means that the hardware is defective. Examples include IEDs, controllers and gateways.

Defective alarms use normally open contacts when hardwired.

10.4.4 Main Protection System Site Specific Functions

10.4.4.1 Distribution System

There are no site specific functions for capacitor banks installed at distribution system voltage.

10.4.4.2 Transmission System

10.4.4.2.1 Over Voltage Tripping

Over voltage tripping may be provided for 66 kV & 132 kV capacitor banks. This protects the capacitor bank an over voltage condition and removes the MVAr source which contributes to the over voltage condition.

The requirement for this function is determined by system simulations, transmission planning and system operations.

10.4.4.2.2 Under Voltage Closing

An under voltage closing function may be required on 66 kV & 132 kV capacitor banks. This control function responds to an under voltage conditions and switches in capacitor banks to provide additional MVAr support for the system.

The requirement for this function is determined by system simulations, transmission planning and system operations.

10.5 Appendix A – Capacitor Bank Design Requirements

Functions		Operation						Indication					
Function Name	**ANSI**	**Initiation**		**Selection**		**Resetting**		**Operation**		**Selection**		**Resetting**	
		A/R	**CB Fail**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**Self**
IDMT Overcurrent	51		Yes			Latched		Yes	Yes			Yes	
Instantaneous overcurrent	50		Yes			Latched		Yes	Yes			Yes	
IDMT earth fault	64		Yes			Latched		Yes	Yes			Yes	
Circuit breaker failure	52					Latched		Yes	Yes			Yes	
UFLS (Circuit stage selection)				Yes	Yes					Yes	Yes		
UFLS (Tripping)	81					Latched	Yes	Yes	Yes			Yes	
Local metering	HMI												
Remote metering	77												
VT failure	47					Latched		Yes	Yes				Yes
Circuit breaker wear monitoring	94.1			Yes						Yes			
Trip circuit supervision	TCM					Self		Yes	Yes				Yes
Dynamic disturbance recorder	DDR												
Sequence of events recorder	SER												
Time synchronisation	CLK								Yes				
Protection defective						Self		Yes	Yes				Yes
Device defective						Self		Yes	Yes				Yes
Circuit breaker mechanism defective						Self		Yes	Yes				Yes

Capacitor out of balance (trip)	60		Yes			Latched		Yes	Yes			Yes	
Capacitor out of balance (alarm)	60					Self		Yes	Yes				Yes
Earth switch enable timer	62					Self		Yes	Yes				Yes
Over voltage trip	59					Latched		Yes	Yes			Yes	
Under voltage close	27					Latched		Yes	Yes			Yes	

Note: Grey areas signify ‘No’ or ‘Not Applicable’

Note: Relay Resetting includes both contact and word bit resetting

10.6 Appendix B – Roles and Responsibilities

10.7 Appendix C – Electrical Model of the Capacitor bank

Reactors must be included in studies.

An electrical model of the capacitor bank is constructed to achieve the following:

1) Confirm the interpretation of the manufacturer's data sheets and drawings. It is standard practice to confirm:

   a) The overall connections of the capacitor bank

   b) The branches and internal structures of the units by carrying out unbalance calculations

   c) Compare results to those shown in the manufacturer's unbalance calculation.

2) Study unbalance conditions to determine suitable COOB alarm and trip settings.

3) Study of unbalance conditions that may be applied on site during commissioning to verify correct assembly of the capacitor bank.

4) The capacitor bank must be modelled in sufficient detail to enable progressive failure of elements to be studied. This is usually involves modelling:

   a) Units or groups of units in each of the phases

   b) One or more units in sufficient detail to simulate progressive element failures.

10.7.1 Formula

The capacitor bank ratings may be influenced by other components or the physical layout of the capacitor bank. The capacitor bank rating therefore does not necessarily relate to the actual reactance of a given unit. The calculations must therefore be based on the ratings of the individual units.

The following formulas are used in the model:

1) Capacitor bank unit reactance

$$X_{unit} = \frac{-j\left(kV_{unit-rated}^{2}\right)}{MVar_{unit-rated}} \quad ohms$$

2) Capacitor bank row reactance

$$X_{row} = \frac{X_{unit}}{\text{units/row}} ohms$$

3) Capacitor bank branch reactance

   Standard series and parallel network analysis is used to determine branch reactance.

4) Series reactor (inductor) reactance

$$X_{reactor} = j(2 \times \pi \times f) \times \text{Inductance(mH)} \rightleftarrows \text{ohms}$$

10.7.2 Required Studies

The following must be considered when determining the required capacitor bank studies:

1) Because the manufacturer’s data is given in terms of the capacitor bank rating, a study must be carried out at capacitor bank rated voltage and current. Capacitors are linear devices so the study results can then be scaled to nominal operating voltage.
2) When the capacitor bank is asymmetrical the manufacturer performs one unbalance study for one side of the capacitor bank. Because Western Power does not always adopt the manufacturer's alarm setting, unsymmetrical banks must be studied for failures on both sides.

10.8 Appendix D – Advantages / Disadvantages

10.8.1 Distribution Second Protection Systems

10.8.1.1 Second Capacitor Main Protection System

Used when a second capacitor bank CT core and circuit breaker trip coil are available for a second main protection scheme.

1) Advantages of this option are:
   a) Only the faulted capacitor bank circuit breaker is removed from service. This limits the number of circuits removed from service when the capacitor bank main protection system is out of service.
   b) Easy conversion to a feeder circuit if required in the future.
2) A disadvantage of this option is that a second protection relay, CT core and circuit breaker trip coil.

10.8.1.2 Transformer LV Protection System

If a second capacitor bank CT core and circuit breaker trip coil are not available the transformer LV protection system can be used to backup the capacitor main protection system.

1) Advantages of this option are:
   a) It takes advantage of existing primary and secondary equipment
   b) The second protection system's circuit breaker mechanism is independent from the main protection system's circuit breaker mechanism
2) Disadvantages of this option are:
   a) An operation removes all of the feeders and capacitor banks supplied from the transformer from service

10.8.1.3 Low Impedance Busbar Protection Providing Backup

When options 1 and 2 are not feasible the backup facility of low impedance busbar relays can be used to trip the transformer LV circuit breaker.

1) Advantages of this option are:
   a) It can be installed at site where options 1 & 2 are not possible
   b) It may be able to take advantage of primary and secondary equipment required for other circuits
   c) The second protection system's circuit breaker mechanism is independent from the main protection system's circuit breaker mechanism
2) A disadvantage of this option is an operation removes all feeder and capacitor bank circuits connected to the busbar from service

10.9 Appendix E – Interlocking

10.9.1 External Timers

Brownfield sites without numerical relays have external timers to perform the interlock time delay [70]. Interlock systems using external timers have the following components:

1) Key switch located on the protection panel. The key switch has the following functions:
    a) When the key switch key is inserted, closing of the circuit breaker is allowed
    b) When the key switch key is removed, a standing trip is applied to the circuit breaker
2) External timer. The external timer receives the key switch key and captures and releases the capacitor bank gate key.

10.9.2 Access the Capacitor Bank

The following steps are taken to access the capacitor bank:

1) The key switch key is removed from the key switch located on the protection panel. Removing the key from the key switch puts a standing trip on the circuit breaker and prevents closing of the circuit breaker.
2) The key switch key is inserted into the external timer.
3) After a time delay of 5 minutes, the capacitor bank gate key is released from the external timer and can be used to open the capacitor bank gate.

10.9.3 Restoring the System

The following steps are taken to restore the interlock system:

1) The capacitor bank gate key is removed from the capacitor bank gate and inserted in the external timer. This releases the key switch key.
2) The key switch key is then inserted in the key switch located on the protection panel. Inserting the key in the key switch removes the standing trip and allows the circuit breaker to be closed.

10.9.4 Supplies

External timers are supplied by 240V AC and are independent from the protection panel supplies.

The key switch located on the protection panel is supplied by the protection panel supply.

[70] Fortress Interlocks are an example of interlocks using external timers

11 Reactor Banks Protection

11.1 Introduction

The purposes of this section are to:

1) Define at a high level the functional requirements for reactor protection in Western Power zone substations and terminal stations

2) Capture information which explains the reasoning behind the reactor protection design and settings

11.2 Scope

This section applies to reactor bank circuits within a Western Power zone substation or terminal substations.

11.3 Functional Requirements

The functional requirements of reactor bank protection systems are:

1) Detect and clear faults in the operating zone.

2) Detect and clear faults within times specified by the Technical Rules.

3) Coordinate with upstream protection systems.

4) Clear faults within the thermal limits of associated primary plant.

5) Prevent access to the reactor bank when equipment not fully isolated.

11.4 Reactor Bank Protection

11.4.1 Introduction

The main purpose of the reactor bank protection system is to minimise danger to staff and loss of supply by clearing faults on the reactor bank. Other purposes include control and monitoring to facilitate operation of the reactor bank.

Reactors banks can be connected to transmission lines (in series or shunt), HV and LV busbars or transformer tertiary windings.

11.4.1.1 Reactor Configurations

In Western Power network, shunt reactor installation predominates the series reactors. Shunt reactors are generally used to regulate the voltage on the network via consuming reactive power from the grid whereas series reactor is to limit fault current to an acceptable level within the equipment withstand capability. The most common reactor configuration in the network are as follows:

1) Star Unearthed Shunt Reactors

2) Star Solidly Earthed Shunt Reactors

3) Series Reactors

11.4.1.1.1 Star Unearthed Shunt Reactor Configuration

Star unearthed shunt reactors are generally applied on lower voltage system (33 kV and below) or distribution network. In new installations, dry type / air core shunt reactors are favoured at this voltage level due to the benefit of lower initial and maintenance cost. Although on some older installation, oil-immersed reactors (one or multiple bank) are still present.

The dry type, air core reactors are single phase units (3) connected (banked) in star to form one three phase unit. The disadvantage of dry type reactors are the limitations on kVA and voltage ratings and the high intensity external magnetic field. In practice, star unearthed shunt reactors are attached to the LV busbar or the tertiary delta winding of the transformer via a circuit breaker/s.

11.4.1.1.2 Star Solidly Earthed Shunt Reactor Configuration

Star solidly earthed reactors are generally applied on high voltage system (66 kV and above) or transmission network. At this voltage level, oil-immersed type shunt reactors are preferred due to higher insulation requirements.

Oil-immersed reactors can be constructed either a single phase or three phase bank, iron core or core less type which can be very similar to the external appearance of conventional power transformers. This type of reactor can also be equipped with tap changers (variable shunt reactors) for greater flexibility and effective control in absorbing reactive power. In practice, star solidly earthed shunt reactor banks (three phase) are connected on one (or both) end of a long transmission line or the HV busbar/s via a circuit breaker.

11.4.1.1.3 Series Reactor Configuration

Series reactors are generally applied on high voltage system (66 kV and above) or transmission network that is intended to limit fault current to an acceptable level within the equipment short circuit rating. In normal operation, continuous current flow through the reactors.

Generally, series reactors in Western Power network are dry type and air core (core less) in construction. In practice, series reactors are connected or tied between two HV busbars.

11.4.2 Design Requirements

Standard functions are provided on all reactor bank circuits to assist with standardisation of protection design and setting files. Site specific functions are provided at the discretion of the protection design engineer.

Section 11.5 outlines the design requirements for standard functions and site specific functions.

11.4.2.1 Residual Current

Residual current measurement of the phase CTs by summing the phase vectors is acceptable if a neutral element is not available.

11.4.2.2 Relay Reset Requirements

A protection scheme that trips for reactor bank faults shall:

1) Latch

11.4.2.3 Load Shedding

All shunt reactor bank circuits in zone substations and terminal stations (except connected on HV) must be incorporated into under frequency and under voltage load shedding schemes. The system operators must have the facility to deselect the UFLS or UVLS for individual reactor banks as required. Refer to Section 13 – Under Frequency Load Shedding and Section 12 – Under Voltage Load Shedding.

11.4.2.4 Interlocks

The protection systems provide all reactor bank circuits with interlocks to prevent:

1) Access to the reactor bank compound when the reactor is not fully isolated.

   At sites with outdoor switching equipment, the reactor bank compound gate key is released from the protection panel when both circuit breaker and disconnector are open and the release timer within the protection relay expires.

   At sites with indoor switching equipment (e.g. switchboard), the reactor compound gate key is released when the earth switch is closed. At some sites, access to the earthing switch requires a key to be able to operate the earth switch. Normally, the earth switch key is captive in the protection panel. The key is released when the output of protection relay energises the earth switch key interlock coil which is initiated by the circuit breaker opening, removing the circuit breaker from service (e.g. racked out, test position) and the release timer within the protection relay expires. With the interlock coil energised and reactor bank disconnected from the system, the earth switch key can be removed from the panel and used to release the deadbolt on the earthing switch thereby the switching operator is able to earth the reactor circuit.

   At some sites, earth switch key is not present where there is earth switch blocking magnet (particularly ABB switchboard). In this case the earth switch can be closed when the output of protection relay energises the earth switch blocking magnet.

   At brownfield sites that do not have a protection relay capable of performing the release timer, an external timer is required. Refer to Section 11.8.

2) Closing the reactor bank circuit breaker

   Until after the key allowing access to the reactor bank compound key is returned to the interlock device or capture mechanism.

N.B: Requirement for gated compound on reactor banks is determined on a case to case basis, hence not all reactor bank installation will have this facility (e.g. HV oil-immersed shunt reactors).

11.4.2.4.1 Indication

Indication to EPCC is required when:

1) The compound gate key has been released.

2) The circuit breaker is ready to be closed. This includes the compound gate key being returned to its capture mechanism.

11.4.2.4.2 Indoor Switchboards

Racking the reactor bank circuit breaker out of service disconnects the circuit breaker auxiliary contacts from the protection relay. The protection relay interprets the status of the circuit breaker as closed which resets the earth switch key (or earth switch blocking magnet for ABB switchboard) release timer. An input from circuit breaker service position switch is included in the protection relay logic to avoid resetting the earth switch key (or earth switch blocking magnet) release timer.

11.4.2.4.3 Two Breakers In Series

Generally, reactors connected on the LV system are preferred to be switched with one (1) three phase circuit breaker same as with other LV circuits (e.g. feeder, capacitor banks, etc.). However, this is not always the case specially on brownfield sites where the possibility to connect the reactors is limited to an existing LV switchboard. Due to the negative impact (e.g. premature ageing, contact wear, etc.) of high transient recovery voltage (TRV) on the switchboard circuit breaker when switching a reactor without an option to replace the existing circuit breaker, an additional outdoor circuit breaker with TRV rating above the prospective transient recovery voltage is installed and connected in series with the switchboard circuit breaker to minimise the impact on the said equipment.

Both the series connected switchboard and outdoor circuit breaker shall be controlled by a singular local and remote control facility. In this case, the design for interlocking must adhere to the following guidelines:

1) Local and/or remote trip (excluding protection trip) of the switchboard circuit breaker is allowed when the outdoor circuit breaker is open.

2) Regardless of the position of the outdoor circuit breaker if the issued trip command originated from the relay fault protection elements, the switchboard circuit breaker must be tripped. However, the trip signal must be time delayed not to exceed 200 milliseconds to allow the outdoor circuit breaker to operate first. No trip signal time delay is required to the outdoor circuit breaker from trip commands originated from relay fault protection elements.

3) Local and/or remote close of the switchboard circuit breaker is allowed when the outdoor circuit breaker is open.

4) Local and/or remote close of the outdoor circuit breaker is allowed when the switchboard circuit breaker is closed.

11.4.2.5 Point on Wave Switching

Reactor banks connected at 220 kV and above have large MVAr ratings which can cause an excessive voltage step when switched. A large voltage step results in excessive circuit breaker contact wear. Point on wave switching of independent circuit breaker poles reduces this voltage step.

11.4.3 Main Protection System Standard Functions

The following standard functions are provided for all reactor bank applications.

11.4.3.1 IDMT Overcurrent

The purpose of IDMT overcurrent is to clear phase faults. IDMT overcurrent is not deliberately limited to 3 phase fault conditions and may also respond to phase to phase faults and earth faults. IDMT overcurrent protects the reactor bank against faults which the instantaneous overcurrent protection is unable to detect.

The settings are selected to meet the following requirements:

1) Pickups determined by the following limits:

    a) Lower limit: The lower limit is calculated from:

        i) The rated current of the reactor bank.

ii) An additional margin = 1.5 (typical)

iii) Allowance for relay errors.

iv) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements.

c) A standard setting of 1.5 times the reactor rated current at the reactor rated voltage is recommended.

2) A standard time multiplier setting (TMS) of 0.05, in conjunction with a standard inverse IDMT curve, has been used successfully in the past. The protection engineer must ensure that:

a) There is adequate coordination with the transformer protection

b) No short circuit ratings are exceeded

c) The total fault clearance time meets the Technical Rules requirements.

11.4.3.2 Instantaneous Overcurrent

The purpose of instantaneous overcurrent is to clear high current, 3 phase and phase to phase faults. In general, the metropolitan distribution system is earthed via earthing transformers which limit the earth fault levels. The instantaneous overcurrent function will therefore not respond to earth faults.

The instantaneous overcurrent must be set high enough to avoid operation for reactor inrush currents. The magnitude of the inrush current depends on:

1) System fault level

2) X/R ratio

3) Reactor rating

4) Reactor design (iron cored or air cored)

In accordance with Australian/New Zealand Standard (AS/NZS 60076.6:2013 – Power transformers – Part 6: Reactors; Annexure B.6 Inrush Current), the worst inrush current occurs when the reactors are switched on at zero crossing of the voltage wave. This will give a linked flux that is twice the steady state value. For a reactor with a linear magnetic characteristic (reactor characteristic considered in this guideline) the peak value of the inrush current is then about twice the peak value of the steady state current. The inrush current level for reactors is represented by the following equation:

$$I_{Peak\ Inrush} = 2\ x\ I_{Peak\ Steady} = 2\ x\ (\sqrt{2}\ x\ I_{Steady}) = 2.8284\ x\ I_{Steady}$$

On reactors with non-linear magnetic characteristic the inrush current level can be more than twice the peak steady state current. The inrush current level can be derived from the magnetic characteristic which is not covered in this guideline.

The gapped iron core design in oil immersed type reactors is subjected to more severe magnetising inrush currents than core less type reactors. Nonetheless this guideline shall apply to both type reactors (core and core less) when setting the instantaneous overcurrent function of the relay.

The standard settings are adopted:

1) Pickup = 2.5 x reactor bank current rating x additional margin

2) Additional margin = 1.3 (typical)

3) Time delay = 0 seconds

11.4.3.3 IDMT Earth Fault

11.4.3.3.1 Star Unearthed Shunt Reactor Configuration

The purpose of IDMT earth fault in this shunt reactor configuration is to clear faults involving earth. Settings are selected to meet the following requirements:

1) Pickup:

   a) Lower limit

      i) Because the reactor bank is not earthed, the IDMT earth fault protection is not required to grade with other protection systems. The pickup can therefore be set to the minimum setting.

   b) Upper limit: Must meet Western Power's sensitivity requirements.

2) Time multiplier setting (TMS). A standard setting of 0.1 has been used successfully in the past. The relay will operate in a definite minimum time of approximately 200 milliseconds when set to the minimum pickup. This is considered acceptable because:

   a) Complete saturation for 10 cycles is unlikely.

   b) Generally, no magnetising inrush on air core reactors (dry type preferred in this configuration)

   c) A TMS of 0.1 has not resulted in an inrush operation in the past.

11.4.3.3.2 Star Solidly Earthed Shunt Reactor Configuration

From previous discussion in Section 11.4.1.1.2 the star solidly earthed shunt reactors are generally applied on the transmission network. In the transmission network, Technical Rules demand high speed clearance of fault to maintain network stability. Thus, equipment connected at this voltage level must be equipped with high speed protection scheme (e.g. REF protection) to comply with the rules.

The purpose of IDMT earth fault in this configuration is to provide backup to the high speed protection schemes in clearing faults involving earth. Settings are selected to meet the following requirements:

1) Pickup:

   a) Lower limit

      i) Because the reactor bank is earthed, the IDMT earth fault protection is required to grade with other protection systems.

      ii) Reactance tolerance is within ± 5% (AS/NZS 60076.6) of the rated reactance. Therefore, the pickup must be set not less than 10% (0.1 per unit) of the rated current to account current imbalance due to variation in reactance.

   b) Upper limit: Must meet Western Power's sensitivity requirements.

2) The time multiplier setting (TMS) must.

   a) Allow the slowest line earth fault protection to grade with the reactor protection system.

b) Allow the terminal or zone substation transformer HV REF earth fault or combined HV/LV REF (autotransformers) protection to grade with the reactor protection system.

c) Allow zone substation LV Standby EF protection to grade with the reactor protection system. Grading requirement is dependent on vector group and the HV and LV earthing method of the transformer.

11.4.3.4 Circuit Breaker Failure

The purpose of circuit breaker failure (CB Fail) is to clear a fault when tripping a circuit breaker fails to clear its contribution to a fault. Failure to clear the fault contribution can be caused either by the circuit breaker failing to open or by a small zone fault.

11.4.3.5 Local Metering

Refer to Engineering Design Instruction – Substation Secondary Systems Design for local metering requirements.

11.4.3.6 Remote Metering

Refer to Engineering Design Instruction – Substation Secondary Systems Design for remote metering requirements.

11.4.3.7 VT Failure

The purpose of VT failure is to distinguish between two distinct conditions. Both of these conditions result in a disturbance or loss of secondary volts from the VTs to the relay. The two conditions are:

1) Primary system fault conditions such as:

    a) Phase to earth faults

    b) Phase to phase faults

    c) Three phase faults

    Under these conditions the relay must recognise that a primary fault exists and operate.

2) Non primary system fault conditions such as:

    a) VT primary isolated by primary switching or primary fuse operation

    b) VT secondary disturbed by secondary fuse, or MCB operation

    c) Secondary wiring interference

    d) Disturbance at the test links

    e) Secondary wiring fault

    Under these conditions the relay must recognise that a fault does not exist and not operate. The protection relay may need to take steps to restrain some protection functions.

11.4.3.7.1 Alarming

The VT is used for SOTF restraint so it is important to alarm for a VT failure. The protection relay is required to raise a VT Fail alarm when:

1) No primary system fault exists and
2) A secondary system fault exists

11.4.3.8 Circuit Breaker Wear Monitoring

The purpose of circuit breaker wear monitoring is to assist in the scheduling of circuit breaker maintenance.

Settings are chosen to allow the relay to calculate and accumulate circuit breaker wear information during each circuit breaker opening action. While circuit breaker wear is more dependent on opening for reactor applications, the opening information is also useful in predicting maintenance requirements.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of circuit breaker wear monitoring.

11.4.3.9 Trip Circuit Supervision

The purpose of trip circuit supervision (TCS) is to supervise the integrity of the circuit breaker trip coil. The trip coil is supervised when CB is in both the open and closed state. TCS also supervises the integrity of some of the associated secondary wiring.

Refer to Engineering Design Instruction – Substation Secondary Systems Design for a detailed description of TCS.

11.4.3.10 Dynamic Disturbance Recorder

The dynamic disturbance recorder (DDR) must be configured so that the recorder captures the:

1) Pre fault waveforms.
2) Post fault waveforms which include circuit breaker failure operations.
3) Post fault waveforms which include clearance by downstream devices within the main protection system operating zone.
4) Reactor bank circuit breakers occasionally have re-strike failures within 200 milliseconds of the circuit breaker opening.

11.4.3.11 Sequence of Events Recorder

The sequence of events recorder (SER) monitors what occurs within the relay during both normal operation and faults. When the SER is triggered, a record is created of these events. A protection trip must trigger the SER.

To simplify the event record and minimise the chance of the relay failing, the following guidelines must be followed when choosing what is to appear in the SER:

1) Do not include word bit outputs of directional elements
2) Do not include word bits that may change state frequently under normal conditions, or near the edge of such conditions

11.4.3.12 Time Synchronisation

The protection relays must be configured to receive the Irig B time code or the SNTP time signal when available. The Irig B clock and the SNTP server provide accurate time stamping for fault events. Irig B is more accurate and preferred when no additional wiring is required.

Irig B is standard for all DNP relays. Irig B is standard on IEC61850 relays when additional wiring is not required (e.g. zone substation HV relays). When additional wiring is required SNTP is used (e.g. zone substation LV relays).

11.4.3.13 Defective Alarms

Protection defective means the protection scheme is defective or DC auxiliary voltage supply is off. At DNP sites this is hardwired from the IED to the RTU and means that the IED is defective. At IEC61850 sites it includes failure of the IEC61850 signalling.

Device defective means that the hardware is defective. Examples include IEDs, controllers and gateways.

Defective alarms use normally open contacts when hardwired.

11.4.4 Main Protection System Site Specific Functions

11.4.4.1 Distribution System

11.4.4.1.1 Over Voltage Closing

An over voltage closing function may be required on 33 kV and below shunt reactor banks. This control function responds to an over voltage condition and switches in reactor banks to consume excessive MVAr from the system which is causing the condition.

The requirement for this function is determined by system simulations, transmission planning and system operations.

11.4.4.2 Transmission System

11.4.4.2.1 High Impedance Schemes

High speed duplicated high impedance schemes with different measuring principle shall be applied to shunt reactors connected on the transmission system voltage to comply with technical rules maximum total fault clearance time requirements.

On series reactors connected between HV busbars, the high speed HV bus zone scheme detects and clears faults on the reactors (reactor within the bus zone protective zone), therefore dedicated high impedance schemes for these reactors are not necessary given that high speed protection is already provided by the bus zone protection.

The basic operating principles of high impedance scheme is discussed in the previous section (Busbar Protection).

11.4.4.2.1.1 Current Measuring Relays

1) Current Setting

    a) Lower limit:

    The current setting (I_{Set}) in current measuring relays must be above the spill current that occurs under maximum through fault conditions. All CTs are PX class therefore the maximum turns ratio error is ±0.25% [71]. The worst case is with one CT having a -0.25% turns ratio error and the other a

[71] AS 61869.2 – 2021

+0.25%. The maximum spill current that can flow into the relay is then ±0.5% of the maximum through fault current on the reactors. I_{Set} must be at least 1.3 times this value.

b) Upper limit:

The relay current setting (I_{Set}) must meet Western Power's sensitivity requirements. Refer to Section 16 – Protection Sensitivity.

2) Series Resistor

a) The series resistor, R_{Series}, in current measuring schemes is used to adjust I_{Relay} to a value less than I_{Set} for through faults with CT saturation. For maximum stability the value of R_{Series} is chosen to allow:

The operating voltage, V_{OP}, to be equal to or less than ½ the minimum CT knee point voltage and

The primary operating current, I_{POC}, to meet Western Power's sensitivity requirements

11.4.4.2.1.2 Voltage Measuring Relays

1) Voltage Setting

a) Lower limit:

Western Power's minimum voltage setting is 50 V.

b) Upper limit:

The relay voltage setting (V_{Set}) in voltage measuring relays must be less than or equal to ½ the minimum CT knee point voltage.

2) Shunt Resistor

a) The shunt resistor, R_{Shunt}, in voltage measuring schemes is used to adjust I_{POC} to a value which meets the design requirements in Busbar Protection Section 4.4.2.8.3.2. R_{Shunt} is also used to adjust VOP to be greater than V_{Set} for through faults with CT saturation. For maximum stability the value of R_{Shunt} is chosen to allow:

V_{Set} to be equal to or less than ½ the minimum CT knee point voltage.

Allows IPOC to be 1.3 times the worst case spill arising from CT errors.

11.4.4.2.1.3 Standard Resistor Values

When possible the resistor values must be selected from the following Western Power stock:

500 ohm, 500 Watt

720 ohm, 350 Watt

1000 ohm, 200 Watt

Note -/+ 5% tolerance in standard resistor used by Western Power.

11.4.4.2.1.4 Metrosil

A metrosil (non-linear resistor) is required on all high impedance schemes.

11.4.4.2.2 Low Impedance Schemes

Duplicated low impedance schemes are another alternative for high speed protection of shunt reactors connected on the transmission system voltage.

11.4.4.2.2.1 *Biased Differential*

The purpose of biased differential is to detect and clear internal faults within the operating zone while remaining stable for external faults. Differential (either high or low impedance type) is a form of unit protection and is standard on all reactors connected to the transmission system. This ensures that the Technical Rules total fault clearance times can be met in all situations.

The settings are selected to meet the following requirements:

1) Pickup: This setting provides restraint against apparent differential current caused by:

    a) Magnetisation current of the protected reactor

    b) Steady state CT errors

2) A setting of 0.10 to 0.15 per unit is recommended.

The operating principles of biased differential scheme has been further discussed in the previous section (Transformer Protection).

11.4.4.2.2.2 *Inrush Inhibit*

The purpose of inrush inhibit is to restrain the bias differential function during inrush conditions that most commonly appear on gapped iron core designed reactors (oil immersed type). Similar to power transformers, the traditional method on providing restraint against magnetising inrush current is based on second harmonics. Restraint is provided when the ratio of the second harmonic to the fundamental component of the inrush current exceeds the inrush inhibit level setting. The setting must be exceeded on 2 of the 3 phases of the reactor HV terminal side contribution to the differential relay. A setting of 15% to 20% (depending on the relay used) is recommended.

Cross blocking, which allows the second harmonic in any one phase to be used as a restraint quantity in any other phase, is always used.

Inrush inhibit is a standard function in all reactor main protection system relays that provide biased differential protection.

11.4.4.2.2.3 Instantaneous Differential

The purpose of instantaneous differential is to detect heavier internal fault on the reactor. This function responds to differential current and does not have any bias or harmonic restraint. It therefore operates faster than the differential element. Instantaneous differential is standard on all reactors with low impedance differential protection.

A setting of 2.0 pu (typical) is recommended.

11.4.4.2.2.4 Restricted Earth Fault

Restricted Earth Fault (REF) protection is another form of unit protection scheme applicable to star solidly earthed shunt reactors. The purpose of REF is to detect and clear faults involving earth (e.g. windings, bushing, etc.) where the operating zone is defined by the reactor HV terminal side phase CTs and the neutral CT. Refer to section 11.9.

REF schemes can be set very sensitive without time delay for detection and fast clearance on earth faults.

The settings are selected to meet the following requirements:

1) Pickups determined by the following:
    a) Lower Limit: The lower limit is calculated from:
        i) Must be stable for through faults
        ii) Allowance for relay errors.
        iii) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements.

11.4.4.2.3 Negative Phase Sequence

The purpose of negative phase sequence (NPS) is to detect single pole open condition on the reactor and to provide backup protection on external unbalance type of fault (primarily two phase fault). The NPS elements do not respond to balanced load so they can be set more sensitively than overcurrent elements.

During a HSSPAR operation in the transmission network, the shunt reactors will experience an amount of negative sequence current like an open pole condition. The maximum pole open time in an HSSPR event is 2 seconds. The reactors must be able hold on this event to let HSSPAR to operate successfully and return to the balanced state.

Negative sequence current is also experienced by the reactor during an external unbalance type of fault. The reactors must provide slow backup to the adjacent protection system in clearing this type of faults.

The NPS function is a combination of a definite time (DT) and inverse time (IDMT) function to optimise the operation of the function. The DT function is dedicated to detect and operate on a single pole open condition where the IDMT function is to backup adjacent protection system in clearing external unbalance type of faults.

The settings are selected to meet the following requirements:

1) The NPS inverse time and definite pickups are determined by the following limits:
    a) Lower limit: The lower limit is calculated from:
        i) Reactance tolerance is within ± 5% (AS/NZS 60076.6) of the rated reactance. Therefore, the pickup must be set not less than 10% (0.1 per unit) of the rated current to account current imbalance due to variation in reactance.
        ii) Allowance for relay errors
        iii) CT errors are small and complex. Upper limit: Must meet Western Power's sensitivity requirements.
2) NPS definite time delay:
    a) Greater than the 2 second HSSPR maximum open pole time
    b) A 20% additional margin.
3) NPS inverse time multiplier setting (TMS):
    a) A standard inverse IDMT curve has been successfully used in the past.

b) Allow the slowest adjacent protection to grade with the reactor protection system on the maximum negative sequence current experienced by reactor during external two phase fault.

c) Allow the CB fail elements to operate first.

11.4.4.2.4 Reactor Mechanical Trips

Oil-immersed reactor bank mechanical trips are brought through the protection relay for the purposes of ensuring that all reactor trips originate from the protection relay. This has the following benefits:

1) Local flagging for mechanical trips does not require separate flagging relays

2) The dynamic disturbance recorder can compare mechanical trips with the operation of relay functions

11.4.4.2.5 Close Supply Supervision

The purpose of close supply supervision is to supervise the integrity of the circuit breaker closing supply and associated secondary wiring.

11.4.4.2.6 Voltage Control

The voltage control is applicable to variable type shunt reactors (VSR) installed in the network.

11.5 Appendix A – Reactor Bank Design Requirements

Functions		Operation						Indication					
Function Name	**ANSI**	**Initiation**		**Selection**		**Resetting**		**Operation**		**Selection**		**Resetting**	
		A/R	**CB Fail**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**Self**
Low Impedance / High Impedance [72]													
Differential	87		Yes			Latched [73]		Yes	Yes			Yes	
Restricted Earth Fault	64		Yes			Latched[73]		Yes	Yes			Yes	
Trip Relay						Latched		Yes	Yes			Yes	
IDMT Overcurrent	51		Yes			Latched		Yes	Yes			Yes	
Instantaneous overcurrent [74]	50		Yes			Latched		Yes	Yes			Yes	
IDMT earth fault	64		Yes			Latched		Yes	Yes			Yes	
Circuit breaker failure	52					Latched		Yes	Yes			Yes	
Negative phase sequence[72]	46		Yes			Latched		Yes	Yes			Yes	
UFLS (Circuit stage selection) [75]				Yes	Yes					Yes	Yes		
UFLS (Tripping)[75]	81					Latched	Yes	Yes	Yes			Yes	
Local metering	HMI												
Remote metering	77												

[72] Required for reactors connected on 66 kV and above only excluding series reactors
[73] Applicable to low impedance schemes
[74] Not required on series reactors
[75] Required for reactors connected on 33 kV and below only

VT failure	47					Latched		Yes	Yes				Yes
Circuit breaker wear monitoring	94.1			Yes						Yes			
Trip circuit supervision	TCM					Self		Yes	Yes				Yes
Dynamic disturbance recorder	DDR												
Sequence of events recorder	SER												
Time synchronisation	CLK								Yes				
Protection defective						Self		Yes	Yes				Yes
Device defective						Self		Yes	Yes				Yes
Circuit breaker mechanism defective						Self		Yes	Yes				Yes
Over voltage close[75]	59					Latched		Yes	Yes			Yes	
Earth switch enable timer	62					Self		Yes	Yes				Yes
Mechanical Trips [76]													
Main tank buchholz			Yes			Latched		Yes	Yes			Yes	
Main tank pressure			Yes			Latched		Yes	Yes			Yes	
Winding temperature			Yes			Latched		Yes	Yes			Yes	
Oil temperature			Yes			Latched		Yes	Yes			Yes	
Oil surge			Yes			Latched		Yes	Yes			Yes	

Note: Grey areas signify ‘No’ or ‘Not Applicable’

Note: Relay Resetting includes both contact and word bit resetting

[76] Required for oil-immersed type reactors only

11.6 Appendix B – Roles and Responsibilities

11.7 Appendix C – Advantages / Disadvantages

11.7.1 Distribution Second Protection Systems

11.7.1.1 Second Reactor Main Protection System

Used when a second reactor bank CT core and circuit breaker trip coil are available for a second main protection scheme.

1) Advantages of this option are:
2) Only the faulted reactor bank circuit breaker is removed from service. This limits the number of circuits removed from service when the reactor bank main protection system is out of service.
3) Easy conversion to a feeder circuit if required in the future.
4) A disadvantage of this option is that a second protection relay, CT core and circuit breaker trip coil.

11.7.1.2 Transformer LV Protection System

If a second reactor bank CT core and circuit breaker trip coil are not available the transformer LV protection system can be used to backup the reactor main protection system.

1) Advantages of this option are:
   a) It takes advantage of existing primary and secondary equipment
   b) The second protection system's circuit breaker mechanism is independent from the main protection system's circuit breaker mechanism
2) Disadvantages of this option are:
   a) An operation removes all of the feeders and reactor banks supplied from the transformer from service

11.7.1.3 Low Impedance Busbar Protection Providing Backup

When options 1 and 2 are not feasible the backup facility of low impedance busbar relays can be used to trip the transformer LV circuit breaker.

1) Advantages of this option are:
   a) It can be installed at site where options 1 & 2 are not possible
   b) It may be able to take advantage of primary and secondary equipment required for other circuits
   c) The second protection system's circuit breaker mechanism is independent from the main protection system's circuit breaker mechanism
2) A disadvantage of this option is an operation removes all feeder and reactor bank circuits connected to the busbar from service

11.7.2 Transmission Protection Systems

11.7.2.1 High Impedance Scheme on Shunt Reactors

1) Advantages of this option are:

   a) Simplicity (e.g. no complex relay programming)

   b) Stability and security (inherent immunity to CT saturation on external faults)

   c) Relay cost is relatively low

2) Disadvantages of this option are:

   a) High CT performance requirements (preferably PX class), in general CTs on the reactor phase and neutral must be identical (e.g. same ratio, excitation and saturation characteristics, etc) to guarantee sensitivity and security. A challenge to implement on brownfield installations due to high CT performance requirements (main CT replacement is necessary).

   b) Risk on personnel safety due to presence of high voltages on the secondary circuit during an internal fault.

   c) Higher installation cost implication due to multiple relays and dedicated high performance CTs (sharing of CT is not recommended) are needed to implement both reactor differential and REF protection.

11.7.2.2 Low Impedance Scheme on Shunt Reactors

1) Advantages of this option are:

   a) Lower CT requirements (e.g. 5P20). Can be applied with different type of CTs at the reactor terminals and starpoint (e.g. CTs doesn't need to be identical).

   b) Less CTs are needed as main CT can be shared with other relays. Both differential and REF protection can be implemented in one (1) numerical type multifunction relay, thus overall installation cost is less to implement an optimum reactor protection.

   c) No risk on safety as in case of an internal fault no high voltages will appear on the secondary circuit.

   d) A better retrofit solution for brownfield site reactor installations.

2) Disadvantages of this option are:

   a) No inherent immunity against CT saturation for external faults as compared to high impedance scheme.

   b) Relay cost is higher than high impedance relay

   c) Setting or programming complexity is determined by the relay manufacturer used.

11.8 Appendix D – Interlocking

11.8.1 External Timers

Brownfield sites without numerical relays have external timers to perform the interlock time delay [77]. Interlock systems using external timers have the following components:

1) Key switch located on the protection panel. The key switch has the following functions:
    a) When the key switch key is inserted, closing of the circuit breaker is allowed
    b) When the key switch key is removed, a standing trip is applied to the circuit breaker
2) External timer. The external timer receives the key switch key and captures and releases the reactor bank gate key.

11.8.2 Access the Reactor Bank

The following steps are taken to access the reactor bank:

1) The key switch key is removed from the key switch located on the protection panel. Removing the key from the key switch puts a standing trip on the circuit breaker and prevents closing of the circuit breaker.
2) The key switch key is inserted into the external timer.
3) After a time delay of 5 seconds, the reactor bank gate key is released from the external timer and can be used to open the reactor bank gate.

11.8.3 Restoring the System

The following steps are taken to restore the interlock system:

1) The reactor bank gate key is removed from the reactor bank gate and inserted in the external timer. This releases the key switch key.
2) The key switch key is then inserted in the key switch located on the protection panel. Inserting the key in the key switch removes the standing trip and allows the circuit breaker to be closed.

11.8.4 Supplies

External timers are supplied by 240V AC and are independent from the protection panel supplies.

The key switch located on the protection panel is supplied by the protection panel supply.

[77] Fortress Interlocks are an example of interlocks using external timers

11.9 Appendix E – Restricted Earth Fault

11.9.1 Earthed Star Point Winding

Shunt reactor restricted earth fault (REF) protection is used to detect and clear internal earth fault. It compares the $3I_0$ flowing in the star point of reactor winding with the sum of the I_0 currents in the three phases. This always sums to zero in a non-faulted winding.

Figure 11.1 – Shunt Reactor REF in-zone fault

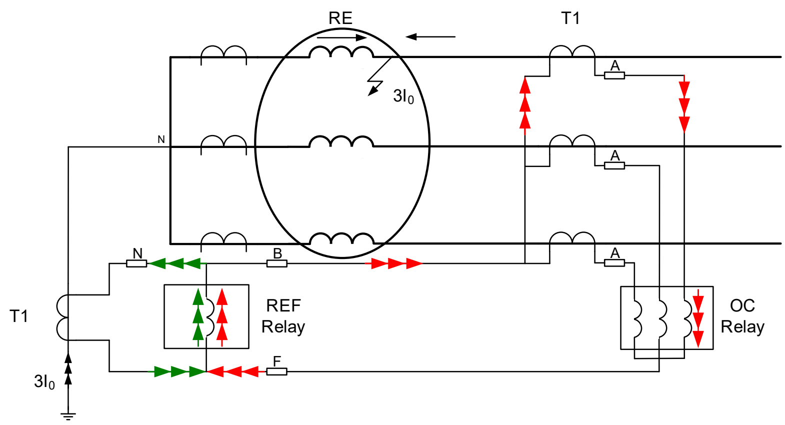
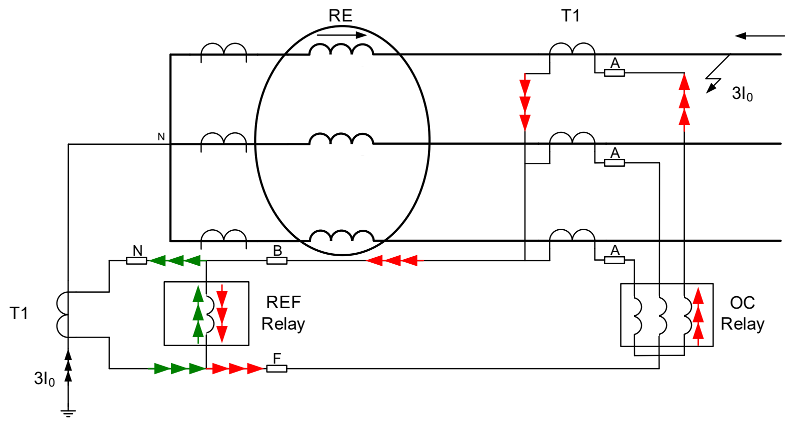


Figure 11.2 – Shunt Reactor REF out of-zone fault



12 Under Voltage Load Shedding

12.1 Introduction

The purposes of this section are to:

1) Define at a high level the functional requirements for under voltage load shedding (UVLS) in Western Power zone substations

2) Capture information which explains the reasoning behind the UVLS design and settings

12.2 Scope

This section applies to under voltage shedding in metropolitan and country zone substations.

12.3 Specific Compliance Requirements

12.3.1 Technical Rules Requirements

Generally, UVLS is applied for operation outside the requirements of the Technical Rules. It is used to attempt to save the system from collapse and prevent damage to customers' equipment.

The Technical Rules require that up to 75% of the system load is available for disconnection by one or more of the following methods [78]:

1) Under frequency relays

2) Manual control

3) Under voltage relays

Protection designs allow up to 100% of load to be selected into or out of the UVLS scheme.

The requirements for steady state power frequency voltage are outlined in clause 2.2.2 of the Technical Rules.

The Technical Rules [79] require that the maximum over voltage in the distribution system be limited to:

1) 30% for a period up to 1 second

2) 20% for a period between 1 and 10 seconds

3) 6% greater than 10 seconds

The Technical Rules [80] require that the maximum over voltage in the transmission system be limited to:

1) 30% for a period up to 1 second

2) 20% for a period between 1 and 10 seconds

3) 10% greater than 10 seconds

[78] Technical Rules clause 2.3.2
[79] Technical Rules clause 2.2.10, Figure 2.1
[80] Technical Rules clause 2.2.10, Figure 2.1

12.4 Functional Requirements

The functional requirements of the under voltage load shedding (UVLS) scheme are:

1) Detect voltage problems on the transmission network
2) Trip an appropriate amount of load when voltages drop below a specified level for a specified time to help aid voltage recovery.

12.5 Under Voltage Load Shedding

12.5.1 Introduction

The voltage profile of the system has a close relationship with the reactive power flow profile. Vars are generated by over excited synchronous generators, capacitors and long, lightly loaded lines. Vars are absorbed by under excited synchronous generators, inductive loads and long, heavily loaded lines. To maintain an acceptable system voltage, the number of vars generated must match the number of vars absorbed.

This equilibrium can be disturbed by:

1) Fault conditions causing generators or lines to trip.
2) Certain transmission plant outages. Lack of local reactive power support can cause the voltage in parts of the system to fall below acceptable levels.

Voltage drop can damage customer equipment. The UVLS scheme helps maintain quality of supply to remaining customers by automatically tripping loads when the voltage reaches an unacceptable level.

12.5.1.1 Metropolitan UVLS

The metropolitan UVLS scheme includes voltage measuring relays at specified terminal stations and zone substations.

12.5.1.1.1 Terminal Stations

Three 330 kV sites, Kwinana (KW), Southern Terminal (ST) and Northern Terminal (NT) are incorporated in the metropolitan UVLS scheme. If the volts at ST or NT are less than 0.85 pu and an under voltage intertrip is received from one of the other two terminals, an intertrip is issued to the zone substations associated with that terminal. As an example, the scheme would operate under the following conditions:

1) The volts at NT are less than 0.85 pu
2) The NT UVLS relay receives an UVLS intertrip from either ST or KW indicating a voltage problem at that site.
3) The NT UVLS relay issues an UVLS intertrip to the Northern UVLS zone substations.

The scheme operates in a similar way for ST and the Southern UVLS zone substations.

12.5.1.1.2 Zone Substations

At zone substations the metropolitan UVLS scheme consists of the following two components:

1) The transmission recovery facility which operates to aid recovery from slowly degrading voltage conditions.

At each metropolitan UVLS zone substation the local UVLS relay detects the occurrence of less than 0.85 per unit voltage. After a delay to ensure a definite period of under voltage, if the voltage is still less than 0.85 per unit, a trip signal is initiated.

The permissive signal from the terminals is combined with the trip signal from the local UVLS relay to trip selected feeders.

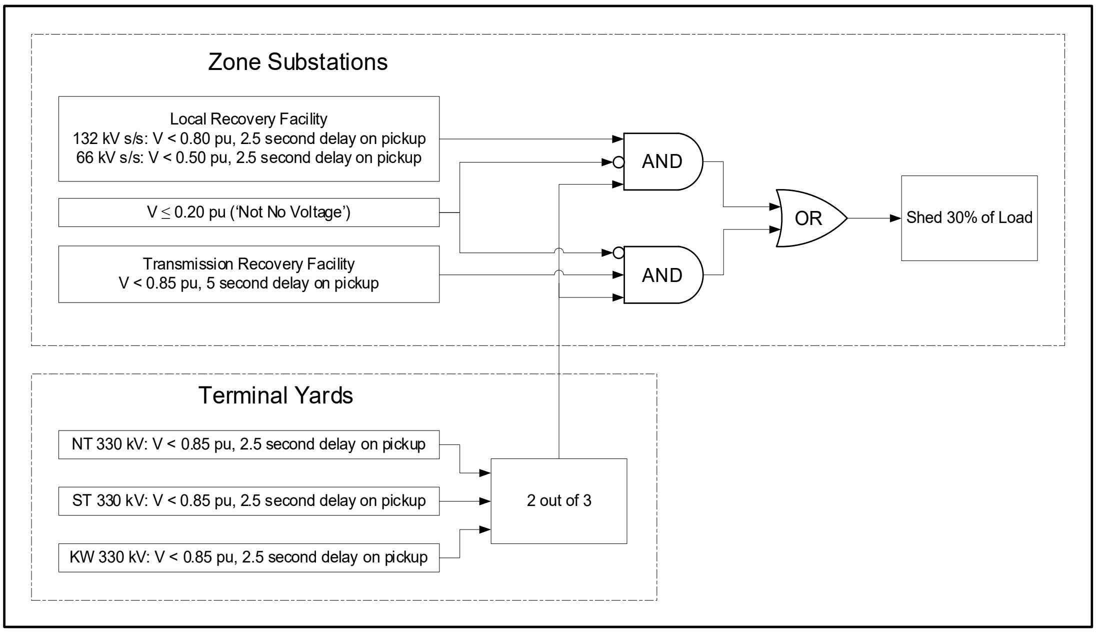
2) The local voltage recovery facility which operates to aid with difficulties in voltage recovery after a fault.

At each 132 kV UVLS zone substation the local UVLS relay detects the occurrence of less than 0.80 per unit voltage. At each 66 kV UVLS zone substation the local UVLS relay detects the occurrence of less than 0.50 per unit voltage. After a delay to ensure a definite period of under voltage, if the voltage is still less than the selected threshold, a trip signal is initiated.

The permissive signal from the terminal stations is combined with the trip signal from the local UVLS relay to trip selected feeders.

A voltage ≤ 0.20 pu not considered to be from an under voltage condition. Under this condition a 'Not No Voltage' blocking signal is utilised to prevent load shedding.

Figure 12.1 – Metropolitan UVLS scheme



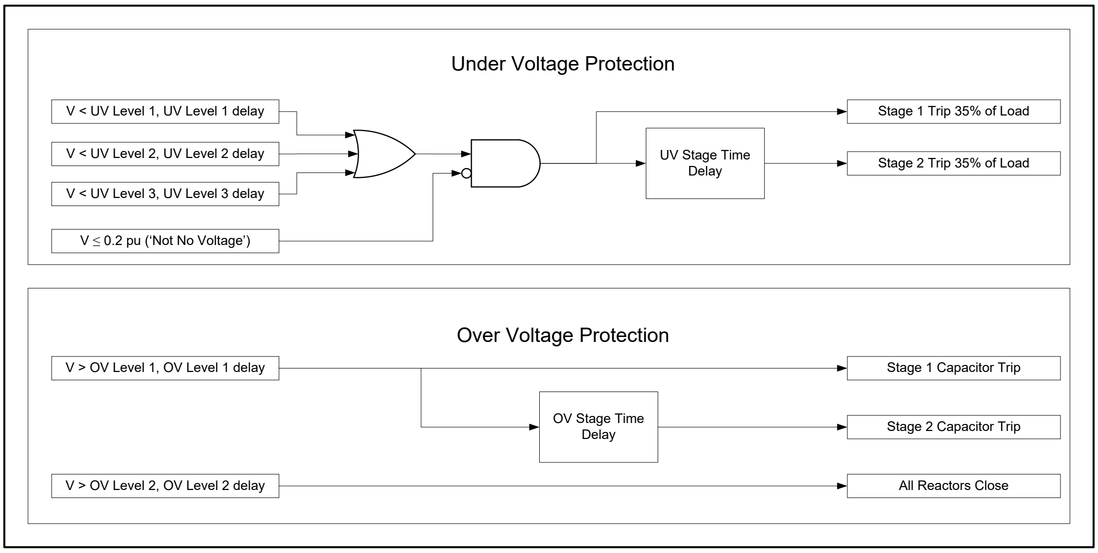
12.5.1.2 Country UVLS

The country UVLS is a distributed scheme which operates independently of the 330 kV terminal stations. Local relays monitor the voltages on the incoming lines. The country UVLS scheme also provides over voltage protection.

The country UVLS scheme has 3 levels of voltage pickup and time delay settings. Each level has progressively lower voltage pickups and shorter time delays. These three under voltage settings are arranged in a two staged tripping sequence.

The country UVLS scheme has 2 levels of over voltage protection. The first level trips capacitors in two stages. The second level closes reactors.

Figure 12.2 – Country UVLS scheme



12.5.2 Design Requirements

Standard functions are provided on all metro and country UVLS schemes to assist with standardisation of protection design and setting files.

Section 12.6 outlines the design requirements for UVLS functions.

At some sites the UVLS scheme trips via a hardwired under frequency load shedding (UFLS) scheme.

12.5.2.1 Defective Alarms

Protection defective means the protection scheme is defective. At DNP sites this is hardwired from the IED to the RTU and means that the IED is defective. At IEC61850 sites it includes failure of the IEC61850 signalling.

Device defective means that the hardware is defective. Examples include IEDs, controllers and gateways.

Defective alarms use normally open contacts when hardwired.

12.5.2.2 DC Supply

UVLS is supplied from the same battery as the circuit breakers it trips to avoid subfusing.

12.5.2.3 Metropolitan UVLS

12.5.2.3.1 Terminal Stations

The protection design and relay settings must meet the following Western Power requirements:

1) A teleprotection signal (TPS) from the UVLS communications rack located at Northern Terminal is required for each Northern UVLS zone substation.

2) A teleprotection signal (TPS) from the UVLS communications rack located at Southern Terminal is required for each Southern UVLS zone substation.

3) Automatic reclose must be inhibited on the ST – SHO/OLY 91 line if the ST 330 kV bus voltage exceeds 1.05 per unit. This functionality is carried out via the SCADA system.

12.5.2.3.2 Zone Substations

The protection design and relay settings must meet the following Western Power requirements:

1) The systems analysis and solutions section will determine the number of and which lines at each substation to be monitored. All three phases must measure low volts for operation. A single phase voltage is acceptable where three phase voltages are not available.
2) UVLS operation shall be blocked should the voltage drop below 0.2 volts per unit. This indicates a VT fail.
3) All feeder, capacitor and reactor circuits will be included in the UVLS scheme. When the load is shed it may be necessary to trip capacitor banks to prevent system voltage rise.
4) The network operation reliability and capacity engineer will determine which feeders and capacitors are selected to be included into the UVLS scheme.

12.5.2.4 Country UVLS

The protection design and relay settings must meet the following Western Power requirements:

1) The systems analysis and solutions section will determine the number of and which lines at each substation to be monitored. All three phases must measure low volts for operation. A single phase voltage is acceptable where three phase voltages are not available.
2) UVLS operation shall be blocked should the voltage drop below 0.2 volts per unit. This indicates a VT fail.
3) All feeder, capacitor and reactor circuits will be included in the UVLS scheme. When the load is shed it may be necessary to trip capacitor banks to prevent system voltage rise.
4) The network operation reliability and capacity engineer will determine which feeders and capacitors are selected to be included into the UVLS scheme.
5) The network operation reliability and capacity engineer will determine which capacitors are selected to be included into the over voltage protection.

12.5.3 Settings

The system analysis and solutions section will determine the required pickup and time delay settings. The protection design engineer is responsible for ensuring that these settings grade with existing substations settings. These include feeder, transformer and LV busbar protection systems and substation integration package (SIP) voltage control systems. These settings must include margins for accuracy and post-fault voltage recovery.

Changes in the transmission network may affect UVLS discrimination. This is especially relevant to the Country UVLS settings. The following are examples of network changes that require a review of the UVLS settings:

1) Changes to the transformer, feeder or busbar pickups or time multiplier settings
2) Changes to the substations integrated package (SIP) voltage control settings
3) Transformer paralleling
4) Addition, removal or reconfiguration of transmission lines

5) Changes in generation

12.5.3.1 Metropolitan UVLS

The metropolitan UVLS scheme has standard settings for both the terminal stations and zone substations.

12.5.3.1.1 Terminal Stations

Pickup = 0.85 per unit.

Time delay on pickup = 2.5 seconds

12.5.3.1.2 Zone Substations

Under voltage blocking = 0.20 per unit

12.5.3.1.2.1 Transmission recovery facility

Pickup = 0.85 per unit

Time delay on pickup = 5 seconds

12.5.3.1.2.2 132 kV substations local recovery facility

Pickup = 0.80 per unit

Time delay on pickup = 2.5 seconds

12.5.3.1.2.3 66 kV substations local recovery facility

Pickup = 0.50 per unit

Time delay on pickup = 2.5 seconds

12.5.3.2 Country UVLS

12.5.3.2.1 Under Voltage Settings

The under voltage pickup is site specific

The country UVLS stage time delay = 0.50 seconds.

Under voltage blocking = 0.20 per unit.

12.5.3.2.2 Over Voltage Settings

The country UVLS over voltage pickup settings are standard and listed below:

1) Level 1 pickup (capacitor trip) = 1.10 per unit, time delay 1.5 seconds.
2) Level 2 pickup (reactors close) = 1.15 per unit, time delay 0.4 seconds.

The country UVLS capacitor stage time delay = 0.50 seconds.

12.6 Appendix A – Under Voltage Load Shedding Design Requirements

Functions		Operation						Indication					
Function Name	**ANSI**	**Initiation**		**Selection**		**Resetting**		**Operation**		**Selection**		**Resetting**	
		A/R	**CB Fail**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**Self**
IDMT Overcurrent	51		Yes			Latched		Yes	Yes			Yes	
Instantaneous overcurrent	50		Yes			Latched		Yes	Yes			Yes	
IDMT earth fault	64		Yes			Latched		Yes	Yes			Yes	
Circuit breaker failure	52					Latched		Yes	Yes			Yes	
UFLS (Circuit stage selection)				Yes	Yes					Yes	Yes		
UFLS (Tripping)	81					Latched	Yes	Yes	Yes			Yes	
Local metering	HMI												
Remote metering	77												
VT failure	47					Latched		Yes	Yes				Yes
Circuit breaker wear monitoring	94.1			Yes						Yes			
Trip circuit supervision	TCM					Self		Yes	Yes				Yes
Dynamic disturbance recorder	DDR												
Sequence of events recorder	SER												
Time synchronisation	CLK								Yes				
Protection defective						Self		Yes	Yes				Yes
Device defective						Self		Yes	Yes				Yes
Circuit breaker mechanism defective						Self		Yes	Yes				Yes

Capacitor out of balance (trip)	60		Yes			Latched		Yes	Yes			Yes	
Capacitor out of balance (alarm)	60					Self		Yes	Yes				Yes
Earth switch enable timer	62					Self		Yes	Yes				Yes
Over voltage trip	59					Latched		Yes	Yes			Yes	
Under voltage close	27					Latched		Yes	Yes			Yes	

Note: Grey areas signify ‘No’ or ‘Not Applicable’

Note: Relay Resetting includes both contact and word bit resetting

12.7 Appendix B – Roles and Responsibilities

13 Under Frequency Load Shedding

13.1 Introduction

The purposes of this section are to:

1) Define at a high level the functional requirements for under frequency load shedding (UFLS) protection in a Western Power zone substation
2) Capture information which explains the reasoning behind the UFLS protection design and settings

13.2 Scope

This section applies to under frequency shedding (UFLS) in metropolitan and country zone substations.

13.3 Specific Compliance Requirements

13.3.1 Technical Rules Requirements

The Technical Rules require that up to 75% of the system load is available for disconnection by one or more of the following methods [81]:

1) Under frequency relays
2) Manual control
3) Under voltage relays

Protection designs allow up to 100% of load to shed by the UFLS scheme. The network operations reliability and capacity engineer is responsible for selecting at which frequency stage the distribution feeders are shed.

The Technical Rules also require switchable capacitors at terminal stations and zone substations to be included in an UFLS scheme [82].

13.4 Functional Requirements

The functional requirements of the under frequency load shedding (UFLS) scheme are:

1) Detect frequency problems.
2) Trip an appropriate amount of load when frequency drops below a specified level for a specified time to help aid frequency stability.

13.5 Under Frequency Load shedding

13.5.1 Introduction

A power system consists of many generators interconnected via the transmission network running at the same frequency. In the South West Interconnected System (SWIS) the frequency is maintained between

[81] Technical Rules clause 2.3.2
[82] Technical Rules clause 2.4.1(b)

49.8 – 50.2 Hz. In equilibrium the electrical power absorbed by the system load is equal to the mechanical power output by the generator turbines.

Equilibrium between power absorbed by loads and power output by the generators can be disturbed by fault conditions causing generators to trip. If the generation is lost frequency will drop.

The UFLS scheme helps maintain power system frequency stability to remaining customers by automatically tripping loads when the frequency reaches an unacceptable level.

13.5.2 Design Requirements

The UFLS relay uses a voltage supply to sense the system frequency. In many older sites the scheme is connected to the 240 V station supply which is stepped down to 110V by a voltage transformer. In newer sites with indoor switchgear, the voltage supply is taken from the 110V secondaries of the LV busbar voltage transformer.

Each stage has a frequency and a time delay setting. The load selected to the stage will trip and lock out when the:

1) System frequency falls below the frequency setting and the

2) Time delay setting is exceeded

If the frequency continues to drop the next stage will trip. This will continue until the frequency stabilises.

New circuits shall have UFLS incorporated in the protection relay when possible.

At some sites the under voltage load shedding (UVLS) schemes trips into the UFLS scheme (e.g. BUH). It may be necessary to include a new circuit in an existing hardwired UFLS scheme when the existing UVLS scheme trips into the hardwired UFLS scheme before the stage selection.

The UFLS stage override facility has been removed. It was originally included to allow the operators to shed load should the UFLS scheme fail. System management have an alternative load shedding facility so the UFLS stage override is no longer required [83].

13.5.2.1 Older Zone Substations

There is a dedicated UFLS panel in older zone substations. The under frequency relays, selector switches and a lockout trip relays for each feeder are mounted on this panel. There is also a common reset relay operated remotely from EPCC and locally via a push button. This relay resets the UFLS lockout trip relays.

13.5.2.2 New Zone Substations

New zone substations with numerical protection relays do not have a hard wired UFLS scheme. Instead the UFLS functionality is provided by the individual feeder or capacitor protection relays. All the functionality of the hard wired scheme is retained in the protection relays. Under voltage blocking is set in the relay to prevent mal-operation for a loss of the voltage transformer. The standard under voltage blocking setting is 20 V.

A facility to remotely select the UFLS stage for individual feeders shall be provided on all circuits using numerical relays to provide the UFLS function.

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[84] Technical Rules clause 2.4.1 Table 2.8

Feeder circuit protection is required to block operation of UFLS when the detected active power direction is reverse (flowing into the transmission system).

13.5.3 Standard UFLS Functions

13.5.3.1 Frequency and Time Delay

The Technical Rules define the under frequency stages for the South West Interconnected System (SWIS) [84]. Table 13.1 and Table 13.2 summarise the under frequency stages, required time delay and amount of load to be shed at each stage.

Capacitor banks are included in the UFLS scheme. The transport of power to the load results in reactive losses that are provided for by capacitor banks. As the load reduces the inductive losses reduce. If the capacitors remain in service the reactive power flow could be back to the transmission system resulting in an excessive voltage rise.

Table 13.1 – South West Interconnected System (SWIS)

Stage	Frequency (Hz)	Time Delay (sec)	Load Shed (%)	Cumulative Load Shed (%)	Capacitor Shed (%)	Cumulative Capacitor Shed (%)
1	48.75	0.4	15	15	10	10
2	48.50	0.4	15	30	15	25
3	48.25	0.4	15	45	20	45
4	48.00	0.4	15	60	25	70
5	47.75	0.4	15	75	30	100

Table 13.2 – North West Interconnected System (NWIS)

Stage	Frequency (Hz)	Time Delay (sec)	Load Shed (%)	Cumulative Load Shed (%)	Capacitor Shed (%)	Cumulative Capacitor Shed (%)
1	49.00	0.5	17	17	17	17
2	48.75	0.5	17	34	17	34

As shown in Table 13.1 and Table 13.2 the UFLS scheme operates at several frequency stages. Each feeder and capacitor can be selected to any of these stages. This selection is done locally at older substations or locally and remotely at newer sites.

[84] Technical Rules clause 2.4.1 Table 2.8

Previous UFLS schemes in the SWIS had 6 stages with the sixth stage set to 47.50 Hz. A review in 1998 found that stage 6 raced with under speed tripping of many gas turbines on the system. Stage 6 was therefore removed.

The Time Delay (sec) is the relay measuring time. The total scheme clearance time will be longer than this.

13.5.3.2 Reverse Power Flow Blocking

New feeder protection installations and protection replacements are required to detect active power flow into the transmission system. Where such a condition occurs, the operation of the under frequency element is to be blocked.

Fleeting assertion of the blocking function may be detrimental to the remaining useful life of the numerical relays' system memory. The blocking function is to utilise a pick-up timer to prevent fleeting assertion of the blocking logic.

13.6 Appendix A – UFLS Design Requirements

Refer to Section 9 – Feeder Protection.

13.7 Appendix B – Roles and Responsibilities

14 Generation Interconnection Protection

14.1 Introduction

The purposes of this section are to:

1) Define the high level functional requirements for the generator interconnection at Western Power zone substations and terminal stations.

2) Capture information which explains the reasoning behind the generator interconnection protection design and settings.

14.2 Scope

This section applies to distribution and transmission connected generators.

The scope of this section does not include the user requirements.

This document makes recommendations agreed to by a number of different stakeholders [85].

14.3 Functional Requirements

Generator interconnection protection systems must meet the functional requirements outlined in Section 2 – Protection Philosophy and Performance Criteria. In addition, generator interconnection designs must provide backup islanding.

[86] Technical Rules clause 3.3.6

14.4 Generator Interconnection Protection

14.4.1 Introduction

Generators are connected to the Western Power system by:

1) A distribution feeder supplied from a zone substation

2) A transmission line supplied from a zone substation or terminal station

14.4.2 Design Requirements

14.4.2.1 General Design Requirements

14.4.2.1.1 Circuit Breaker Failure

The purpose of circuit breaker failure (CB Fail) is to clear a fault when tripping a circuit breaker fails to clear its contribution to a fault. Failure to clear the fault contribution can be caused either by the circuit breaker failing to open or by a small zone fault.

Refer to Section 8 – Circuit Breaker Protection for a detailed description of CB Fail.

14.4.2.1.2 Synchronism

There is no Western Power requirement for synchronisation at the zone substation or terminal station. This function must be provided by the user's protection systems [86].

Check synchronism in zone substations is not required at distribution voltages.

Check synchronism on lines connected to a generator is standard at transmission voltages. Refer to Section 8 – Circuit Breaker Protection.

14.4.2.1.3 Sensitivity

Protection systems must meet Western Power's sensitivity requirements. Addition of a distribution generator can cause or increase feeder sensitivity problems when the feeder's second protection system is provided by the transformer LV overcurrent function. Refer to Section 16 – Protection Sensitivity.

14.4.2.2 Distribution System Design Requirements

The detail in this section describes additional general requirements for connecting a private parallel generator (PPG) to the Western Power distribution system. A network control service (NCS) may have unique requirements to be assessed on a case by case basis. It is the responsibility of distribution planning to:

1) Ensure the distribution system, including the user's facility, meets the Technical Rules requirements

2) Inform protection design of distribution requirements to meet the Technical Rules

Generators connected to the distribution system are generally less than 10 MW. Additional requirements for generators greater than 10 MW are outlined in section 3.5.2 of the Technical Rules.

[86] Technical Rules clause 3.3.6

14.4.2.2.1 Main Protection System

The main protection system provides backup for the first recloser in series. The main protection system's operating zone extends to the second recloser to provide backup for the first recloser. If a first or second recloser is not installed on a feeder branch, the main protection system operating zone extends to the:

1) Fuses of all distribution transformers of that branch, and

2) HV terminals of all user's HV circuit breakers if a generator is connected to the branch

Refer to Section 14.7.

Refer to Section 9 – Feeder Protection for a discussion feeder main protection system requirements.

14.4.2.2.2 Second Protection System

The second protection system provides backup protection for the main protection system. The second protection system's operating zone extends to the first recloser to provide backup for the feeder main protection system. If a recloser is not installed on a feeder branch, the second protection system operating zone extends to the:

1) Fuses of all distribution transformers of that branch and

2) HV terminals of all user's HV circuit breakers if a generator is connected to the branch

Refer to Section 14.7.

Refer to Section 9 – Feeder Protection for a list of acceptable second protection systems.

14.4.2.2.3 Automatic Reclose

Refer to Section 8 – Circuit Breaker Protection for a detailed description of automatic reclose.

During an automatic reclose cycle on a non-dedicated generator feeder:

1) The Western Power feeder circuit breaker will disconnect the generator from the Western Power network. This will temporarily island the generator.

2) An inter trip will be sent to the generator RTU

3) If the generator's islanding system has not operated, the inter trip must be actioned before the auto reclose sequence commences.

4) When a feeder circuit breaker's dead time expires, the circuit breaker recloses.

The generator must be disconnected before the circuit recloses to prevent a possible out of synchronism reclosure. To ensure this the automatic reclose dead time must be longer that the inter-trip time.

The Technical Rules require that a generator provide fully functional islanding protection [87]. If the load on the feeder matches the output of the generator, the generator may not detect an islanding condition. The Technical Rules require Western Power to provide an inter-trip link to function as a backup to the user's islanding protection when there is a risk of an undetected islanding condition [88]. Western Power considers the options outlined in Table 14.1 below acceptable to meet the backup requirement implied in the Technical Rules.

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[87] Technical Rules clause 3.5.2 (d), Generators ≥10 MW; clause 3.6.10.3 (a,b), Generators < 10 MW

[88] Technical Rules clause 3.6.11, Generators < 10 MW

Table 14.1 – Automatic Reclose Out of Sync Close Options

Preference	Solution
1	Use the open generator feeder circuit breaker status to disconnect the generator from the system before the feeder automatic reclose dead time expires.
2	Use a voltage relay to prevent a reclose when a downstream voltage is present
3	Apply check synchronism to the feeder circuit breaker

Refer to Section 14.8 for a list of advantages and disadvantages of each preference.

Reclosers have live line blocking to prevent an out of synchronism reclosure.

14.4.2.2.3.1 Communications Failure

A loss of the communications signal must:

1) Trip the generator if it is established that the communications system has failed. Time delays are introduced so that fleeting interferences do not trigger this trip unnecessarily.

2) Disable automatic reclose on the generator feeder circuit breaker.

14.4.2.2.3.2 Communications Fail Time

The total communications fail time can vary, depending on the particular communications path that is installed. ***Circuit Breaker Failure***

14.4.2.2.4.1 Customer Main Switch Failure

It is the user's responsibility to clear a fault in their facility if the customer main switch (CMS) fails to clear the fault. Western Power does not provide backup protection for a failure of the user's HV or LV circuit breakers. If the generator feeder circuit breaker failure (CB Fail) protection scheme is taken out of service, the generator must be disconnected.

14.4.2.2.4.2 Circuits Adjacent to the Generator Feeder

Adjacent feeder and transformer circuits can be affected by a generator. The generator will provide current to faults on adjacent feeders which will lower the transformer's fault current contribution. The lower transformer fault contribution may cause sensitivity problems if the adjacent feeder backup protection system is provided by the transformer LV protection system. If an adjacent feeder or transformer LV circuit breaker fails to open, the generator may continue to supply fault current to a feeder or transformer fault. Designs must conform to Section 16 – Protection Sensitivity.

Because of relatively high fault levels on distribution busbars, distribution capacitors on adjacent circuits usually do not have sensitivity problems.

14.4.2.2.4.3 Direct and Indirect Connections

A generator can be connected to an adjacent feeder circuit or transformer circuit either directly or indirectly:

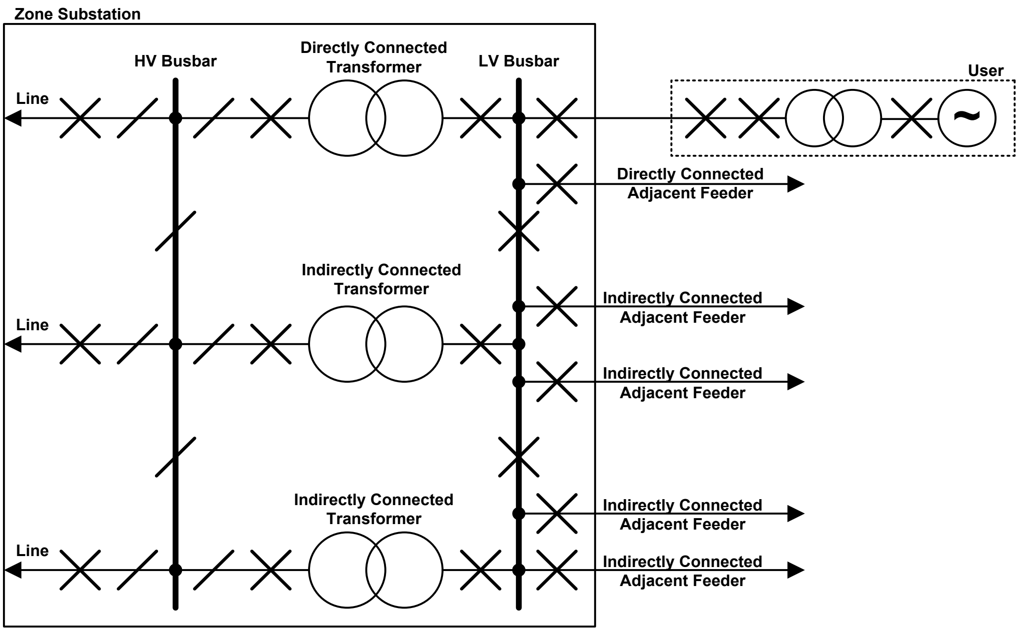
1) Direct connection: the adjacent feeder or transformer CB and generator feeder CB are directly connected to the same busbar.

2) Indirect connection: the adjacent feeder or transformer CB and generator CB are connected to different busbars. The generator is connected to the adjacent busbar/s via circuit breakers or disconnectors.

Note that a generator may have constrained access where it is only permitted to operate when connected under certain operating conditions. For example, a generator may not be permitted to operate under an indirect transformer connection. This may reduce the scope of work.

Figure 14.1 below demonstrates these connections.

Figure 14.1 – Direct and Indirect Connections



14.4.2.2.4.4 Adjacent Feeder Faults

One of the following tripping arrangements shall be implemented:

1) LV busbar protection is available.

   A feeder CB Fail protection or transformer LV protection must trip into its respective busbar protection system. This will clear any fault contributions from the generator as the busbar protection will:

   a) Trip the generator feeder in the case of a directly connected adjacent feeder backup protection operation; or

   b) Trip the bus section circuit breakers in the case of an indirectly connected adjacent feeder backup protection operation.

2) LV busbar protection is unavailable.

   A feeder CB Fail protection or transformer LV protection must trip the generator feeder with either a direct trip or an indirect trip.

   For faults on indirectly connected feeders, the preferred method is to trip the generator feeder via a dedicated logic controller relay for CB fail or transformer LV protection operation. This allows the bus section circuit breakers or bus disconnector auxiliary switches to condition the trip signals.

3) Special conditions for indirect transformer connections.

   In situations where the embedded generator may be permitted to generate when connected to an indirectly connected transformer, relay failure conditions on directly connected adjacent feeders must be accounted for. Solutions include:

   a) Duplicated feeder protection on directly connected adjacent feeders; or

   b) Installation of a dedicated logic controller to trip generator feeder, based on indirectly connected transformer LV OC protection trip and status of bus section circuit breakers or bus disconnector auxiliary switches.

14.4.2.2.4.5 Power Transformer Faults

1) Transformer faults (including HV small zone).

   Generator fault contributions to a transformer or transformer HV small zone fault must be cleared for a transformer LV circuit breaker failure. To ensure this, one of the following tripping arrangements shall be implemented for directly and indirectly connected transformers:

   a) Transformer LV CB Fail and LV busbar protection are both available.

      All transformer and HV busbar protection schemes shall initiate the transformer LV CB Fail. The transformer CB Fail will trip the LV busbar protection system.

      Transformer LV CB Fail functionality shall utilise both current-check and auxiliary status check philosophies.

   b) Transformer LV CB Fail is available but LV busbar protection is not available.

      All transformer and HV busbar protection schemes shall initiate the transformer LV CB Fail. The transformer CB Fail will trip the generator feeder either directly or indirectly.

      For indirectly connected transformers, the preferred method is to trip the generator feeder via a dedicated logic controller relay. This allows the bus section circuit breaker or disconnector auxiliary switches to condition trip signals.

      Transformer LV CB Fail functionality shall utilise both current-check and auxiliary status check philosophies.

2) Neither transformer LV CB Fail nor LV busbar protection is available.

   All transformer HV busbar protection schemes shall trip the generator feeder either directly or indirectly.

   The preferred method is to trip the generator feeder via a dedicated logic controller relay. This allows the bus section circuit breaker or disconnector auxiliary switches to condition trip signal.

3) HV earth faults

   When the HV winding of the power transformer is not earthed, there will be no LV current for an earth fault on the HV winding. When neutral voltage displacement is present on the generator HV it should detect the fault and trip the generator. To keep designs consistent both the transformer HV and LV protection systems will trip the generator feeder for CB Fail conditions. Examples include:

   a) Delta / Star transformers

b) Star / Delta / Star transformer with the HV winding not earthed.

14.4.2.2.5 Transmission Line Faults

A zone substation with a connected generator may have a radial supply from a single transmission line. This could be the result of:

1) A substation with only 1 transmission line

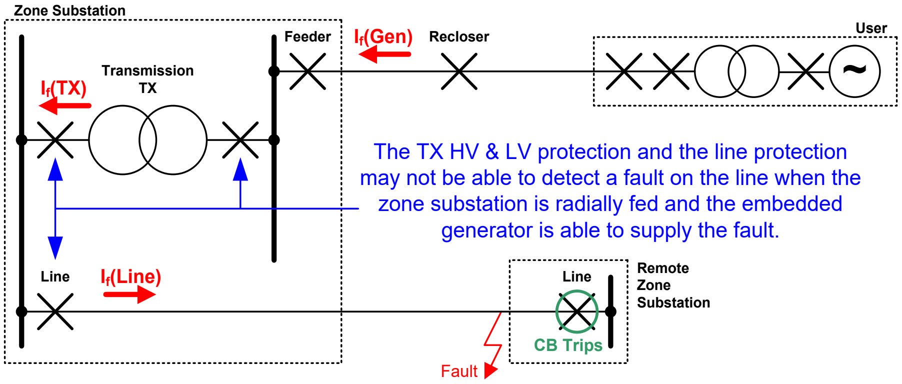
2) A substation with multiple transmission lines with all but one transmission line being out of service.

When a substation is radially fed, the only source of current from that substation to a transmission line fault is from the connected generator. If this is a small generator, the fault contribution to the generator may result in a weak infeed condition.

Some protection schemes cannot detect and clear weak infeed faults. These are typically non-communications assisted schemes and include time stepped distance and earth fault. The solution for clearance of weak infeed faults is dependent on system conditions as outlined below.

Figure 14.2 below demonstrates the weak infeed problem when a fault is supplied from a distribution generator.

Figure 14.2 – Fault on Transmission Line Fed from Generator

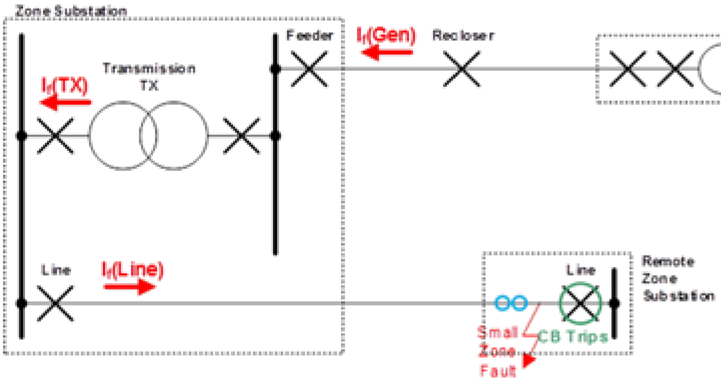


It is expected that a remote end small zone fault can be cleared by PPG anti islanding protection. It is therefore important that PPG facility will need to be fully compliant to its Technical Rules Obligation. Refer to Section 14.6.

The only alternative method to clear this type of fault is have a direct intertrip sent from the Remote Zone Substation upon its buszone protection operating. This solution however, can potentially compromise other technical obligation for network security & stability because the protection system cannot discriminate between a busbar fault and a line small zone fault and therefore is not recommended.

Figure 14.3 below demonstrates the remote end small zone fault, weak infeed problem when a fault is supplied from a distribution generator.

Figure 14.3 – Fault on Transmission Line small zone from Generator



14.4.2.2.5.1 Normal System Conditions

Western Power must detect and clear all faults within the Technical Rules clearance times when a substation is radially supplied during normal system conditions. Western Power must ensure that the installed line protection can detect and clear a generator's fault contribution.

14.4.2.2.5.2 Single Primary Outage

Where a single primary outage results in a radially fed substation, Western Power must detect and clear all faults within Technical Rules clearance times. If the line protection cannot detect and clear the generator contribution to a fault, two solutions should be presented to the customer:

1) Disconnect the generator when the substation has a radial supply. This solution is normally implemented with logic in the X/A 21 master station. The master station must monitor the line circuit breaker statuses to determine if a radial supply exists. If a radial supply exists an inter-trip is sent to the user's customer main switch. This can be done via the SCADA system. This solution is likely to be the less expensive of the two options, but restricts the customer's access to the network.

2) Upgrade the line protection to a system that can detect weak infeed. This solution may include upgrading the communications network. The cost of this solution is therefore potentially significantly more expensive, but allows unconstrained access to the network.

14.4.2.2.5.3 Multiple Primary Outages

An abnormal equipment condition exists when two primary outages results in a radial supply. Under abnormal equipment conditions, a protection system must detect and clear a fault; however, clearance times are not defined.

Under abnormal equipment conditions, the user's protection system or anti-islanding schemes must clear the generator's contribution to a fault.

14.4.2.2.6 Relay Reset Requirements

A protection device that trips a generator circuit can be either self or hand reset, depending on the intended functionality.

Current practice uses hand-reset for CB Fail, transformer and busbar trips. The addition of a generator to the substation does not change this.

14.4.2.2.7 Islanding

When a generator becomes islanded, it may drift out of synchronism with Western Power's system. There is no VT on the feeder side of the circuit breaker so check synchronism cannot be used to prevent closing two out of sync systems. The generator must therefore be disconnected from the system when islanded.

The risks of a generator maintaining supply to an islanded section of the network include:

1) Possible damage to generator and other customers' equipment when the voltage and frequency of the islanded section is outside acceptable limits.

2) Safety risk for personnel working on the islanded section who are not aware that the islanded section is still energised.

3) Reconnection of the still energised islanded section to the network may cause damage if the two sections are out of synchronism.

In order to minimise the above risks, Western Power must ensure that a generator is disconnected when it is islanded.

14.4.2.2.7.1 Detection

Evidence suggests that the generator islanding schemes may not detect an islanding condition if the load on the generator feeder closely matches the output of the generator. Western Power must therefore provide a backup islanding scheme. This backup islanding would normally reside in the substation RTU. This scheme will detect primary equipment configurations local to the zone substation that represent an islanding condition.

1) Single LV busbar substations. Islanding will be detected using auxiliary switches from:

    a) Transformer HV and LV circuit breakers

    b) Bus section LV circuit breakers or disconnectors if there are no bus section LV circuit breakers

    HV disconnectors and line protection circuit breakers are not required.

2) Multiple HV or LV busbars. The configuration of the backup islanding protection will be decided on a case-by-case basis. This will occur at A2 stage in consultation with the market strategic development section.

The generator feeder's circuit breaker status will always be sent to the user's site. The user's customer main switch must be opened when the generator feeder circuit breaker is open.

14.4.2.2.7.2 Inter-trip

An inter-trip will be sent to the customer main switch when:

1) A Western Power protection operation results in an islanding condition

2) The generator feeder's circuit breaker is opened by a control signal

This inter-trip can be done via the SCADA system.

14.4.2.2.7.3 Inter-trip – Critical Services

For customers that are deemed to be a critical services such as hospitals, the intertrip requirement and arrangement requires the approval of the Automation Control Area Manager.

14.4.2.2.8 Close Enable Interlock

All generating units exporting 1 MVA or more to the distribution system must provide for a close enable interlock to prevent closing the user's CMS until permitted by NOCC.

14.4.2.2.9 Close Inhibit Interlock

For large generator installations connected to the distribution system a close inhibit interlock is required [89]. This interlock is implemented with the feeder circuit breakers auxiliary contacts. This interlock prevents closing the user's CMS until Western Power's feeder circuit breaker is closed.

14.4.2.2.10 Metering

MW and MVAR metering is used to identify network security issues and to evaluate the impact of planned outages. At some existing sites only LV volts and feeder current are sent to EPCC. The MWs and MVARs are estimated assuming the same power factor across all feeders. On feeders with connected generation it is necessary to have direct MW and MVAR metering from a transducer or feeder relay. If this can't be achieved with the existing equipment, then Network Operations needs to advise if this requirement is necessary.

14.4.2.3 Transmission System Design Requirements

Generators connected to the transmission system are generally larger than 10 MW. These generators must therefore meet the requirements for generators less than 10 MW plus additional requirements outlined in section 3.5.2 of the Technical Rules.

14.4.2.3.1 User's Facility Design Checks

For transmission system connected generators, protection design is responsible to ensure that the user's facility meets conditions required for power system security. Short circuit faults in the user's facility will generally fall into one of the following categories:

1) Type 1. The short circuit fault directly affects the system security and / or quality of supply. An example of this is a bolted three-phase short circuit fault in the generator stator. This would bring down the voltage of the Western Power network at the time of fault.

   The protection design engineer must review the generator protection systems for Technical Rules compliance and good industry practice. This is to ensure that faults within the generator facility have minimised impact on the SWIS. Included in this review are:

   a) Requirements for main and backup protection systems. This includes independent power supplies.

   b) Western Power's requirement that relays satisfy the requirement for no common mode failure:

      i) Different manufacturers with different hardware, operating principles and algorithms

      ii) Same manufacturer with different hardware (includes input elements and output contacts), operating principles and algorithms.

2) Type 2. The short circuit fault within the user's facility does not directly affect system security and / or quality of supply. The following are examples:

[89] Technical Rules Clause 3.5.2 (f)

a) An earth fault on the generator (delta) side of a delta-star step-up transformer. This earth fault will not directly affect the Western Power network at the time of fault because of the zero-sequence isolation of the delta-star transformer. However if this fault remains uncleared it could potentially damage the generator's installation

b) An inter-turn fault inside the unit transformer windings (protected by the transformer's mechanical protections or transformer restricted earth fault). This would have negligible affect on the Western Power network, but could permanently damage the unit transformer.

If either of these faults remain uncleared, then the primary plant is likely to be damaged. This would have a consequential impact on the network in that this source of generation is then out of service for an extended duration. The fault itself, however, would not adversely affect the operation of the Western Power network at the time of fault.

Extensive review of the generator protection schemes for type 2 faults is not necessary. If an issue concerning a type 2 fault is discovered during the type 1 fault review, it must be brought to the attention of the user. Follow up by Western Power is not required.

14.4.2.3.1.1 Duplication of User Protection

The following protection functions must be duplicated in the user’s protection system:

1) Out of Step
2) Loss of excitation. Control systems may be used to implement one of the schemes.
3) Generator and step-up transformer differential protection. Use of one overall differential scheme, one transformer differential scheme and one step-up transformer differential scheme provides some backup for an LV CB failure.
4) HV CB Fail. Protects against failure of the customer’s main switch (CMS).

The following functions are required but do not need to be duplicated:

1) Reverse power. Loss of excitation protection also protects against reverse power so the reverse power function does not need to be duplicated.
2) Over frequency. Governor control also protects against over frequency so duplication of the over frequency function is not required.

Complementary mechanical protections to the electrical transformer protections must be utilised. Refer to Section 6 – Transformer Protection for a discussion on complementary functions.

14.4.2.3.2 Main Protection System

The operating zone of the main protection system is defined by the current transformers at each end of the transmission line. Each main protection scheme must be able to protect the line with the other main protection scheme out of service.

At voltages of 220 kV and above, both main protections schemes at both ends of the line must be digital differential or interlocked distance to meet total fault clearance time requirements. Below 220 kV interlocking may be required to achieve critical fault clearance times. Refer to Section 3 – Transmission Line and Cable Protection.

System backup time stepped distance shall be provided with the Western Power line protection schemes for all user installations. This provides some protection for the SWIS should there be a catastrophic failure within the user's facility (e.g. both batteries fail).

14.4.2.3.3 Backup Protection System

The line's backup protection system operating zone is defined by the small zone between the line circuit breakers and current transformers. Refer to Section 3 – Transmission Line and Cable Protection.

14.4.2.3.4 Synchronism

Check synchronisation is a standard function on transmission circuit breakers connected to generators. Refer to Section 8 – Circuit Breaker Protection.

14.4.2.3.5 Automatic Reclose

Generators connected at transmission voltages are connected by dedicated lines. Automatic reclose is not provided on these lines.

14.4.2.3.6 Circuit Breaker Failure

On non-dedicated feeders it is the user's responsibility to clear faults within their facility if the customer main switch fails to clear the fault.

14.4.2.3.7 Relay Reset Requirements

Except for CB Fail and busbar protection operations, a protection device that provides tripping for generator circuit shall be self resetting. This allows the control centre to reconnect the generator circuit without attending site.

14.4.2.3.8 Inverter Connected Generation

Because the output of wind farms can vary from 0 to rated output total fault clearance times can be impacted. Depending on the system configuration a weak in-feed condition can be created. Modern protection relays can detect a minimum fault current of about 0.1 A secondary. If the fault current output of the wind farm is less than this, the protection relay will not detect it.

The regulation and sustainability branch has set the following technical requirements [90]:

1) No exemption from the Technical Rules is required if the wind farm is able to feed into a fault at rated output, when operating at full capacity, for a remote total fault clearance time.

2) No exemption from the Technical Rules is required if the wind farm contributes no current to a fault when operating as a load (no wind)

3) In the event of a main protection system failure the wind farm is required to contribute full rated output, when operating at full capacity, to a remote fault for a period of Technical Rules CB Fail time + 50 ms. This is sufficient time to allow the CB Fail function to clear the fault. This applies to both Western Power circuit breakers and the customer main switch.

   When the wind farm is not able to meet condition 3 above the circuit breaker must be monitored using a combination of current monitoring and circuit breaker auxiliary contacts. A CB Fail must annunciate to EPCC. Primary maintenance staff can then be dispatched to repair the faulty circuit breaker.

[90] Mumbida Wind Farm – Summary of Protection Evaluation

In order to detect weak infeed faults and meet the above requirement it is necessary to implement:

a) Line protection systems with weak in-feed functionality

b) CB Fail protection conditioned with both circuit breaker auxiliary contacts and current monitoring when wind farm cannot meet requirement 3 above. This is necessary on:

   i) Circuit breakers connecting the generator to the Western Power system

   ii) Circuit breakers on adjacent circuits which may experience weak in-feed current from the generator.

14.5 Appendix A – Under Voltage Load Shedding Design Requirements

Refer to Section 9 – Feeder Protection and Section 3 – Transmission Line and Cable Protection for standard feeder and transmission line design requirements.

Functions		Operation						Indication					
Function Name	**ANSI**	**Initiation**		**Selection**		**Resetting**		**Operation**		**Selection**		**Resetting**	
		A/R	**CB Fail**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**EPCC**	**Local**	**Self**
Circuit breaker status									Yes				
Circuit breaker fail									Yes				
Additional islanding logic									Yes				
Disconnector status									Yes				

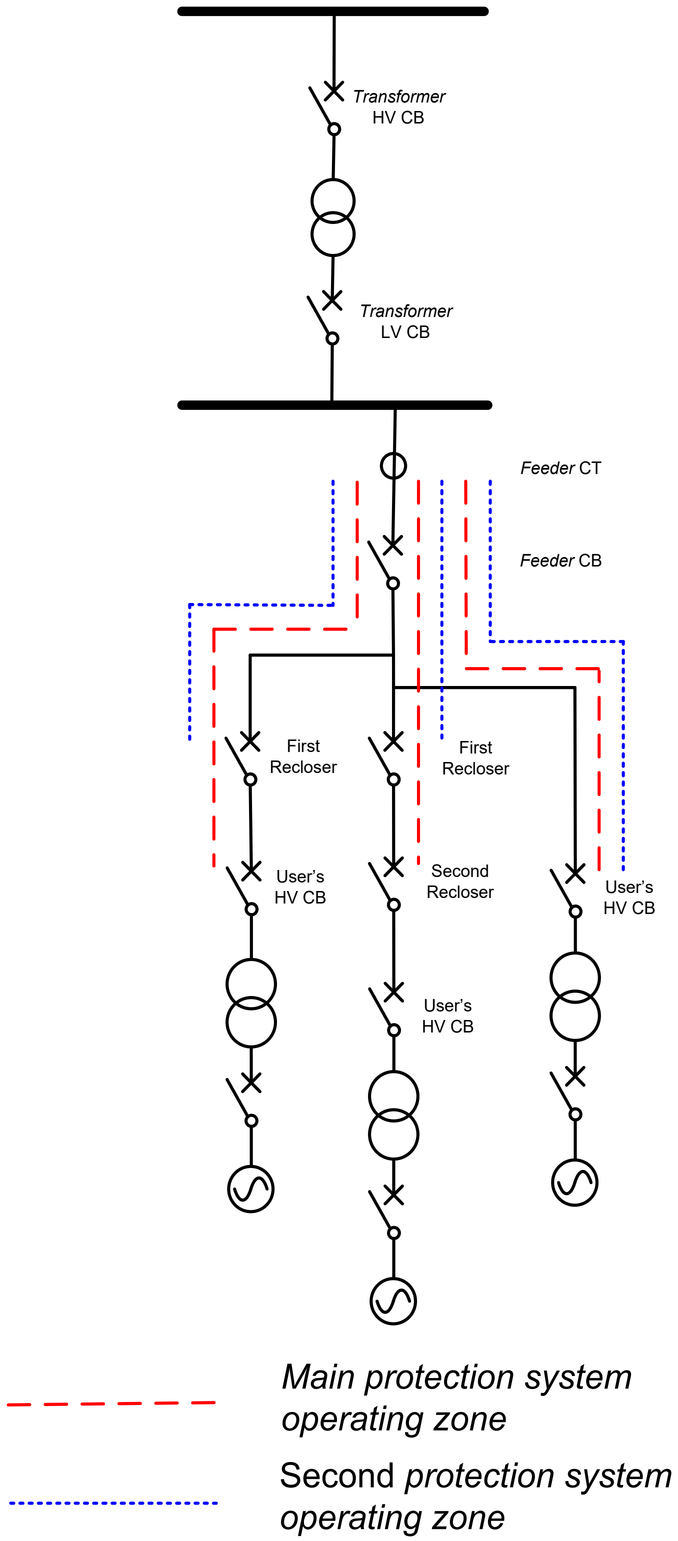
Note: Grey areas signify ‘No’ or ‘Not Applicable’

Note: Relay Resetting includes both contact and word bit resetting

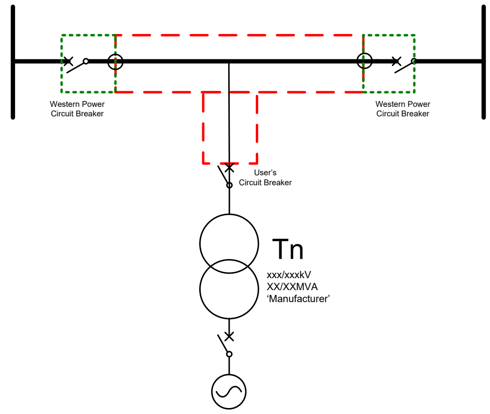
14.6 Appendix B – Roles and Responsibilities

14.7 Appendix C – Operating Zones

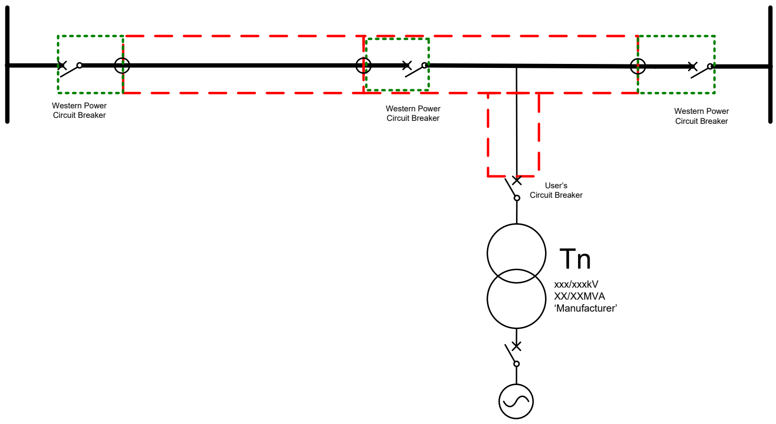
14.7.1 Distribution Voltage



14.7.2 Transmission Voltage

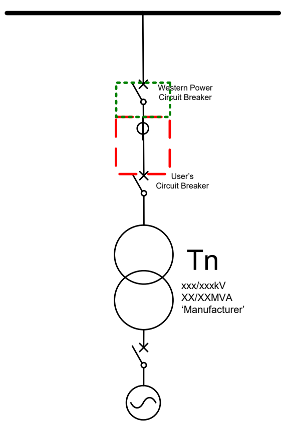


Double busbar configuration



1.5 CB busbar configuration

Single busbar configuration



Main protection system operating zone
Backup *protection system operating zone*

14.8 Appendix D – Design Options

14.8.1 Sensitivity

If a distribution or transmission circuit does not comply with the Technical Rules sensitivity requirement, the noncompliance must be entered into the Technical Rules Non Compliance – Protection register.

Refer to Section 16 – Protection Sensitivity for a discussion and recommendations which may result in compliance.

14.8.2 Automatic Reclose Dead Time

14.8.2.1 Trip Generator Before Dead Time Expires

1) Advantages
    a) Does not require additional equipment
2) Disadvantages
    a) The circuit breaker status inter-trip is sent via a communications link between the remote terminal unit (RTU) and the user's remote monitoring equipment (RME). The automatic reclose dead time must be set in excess of the time required to send the circuit breaker status from the zone substation to the user's (RME). The speed of the communications path must be verified with the SCADA engineer for each installation [91].

14.8.2.2 Close Inhibit Signal

1) Advantages
    a) Does not require additional equipment. Note that a high speed communications link is not required as this is a backup to the generator islanding protection.
    b) Confirms that the generator is disconnected before reclosing the circuit breaker
2) Disadvantages
    a) An additional signal is required. The dead time must be in excess of the communications time required to send the circuit breaker status and receive the generator disconnected status.

14.8.2.3 Live Line Inhibit

1) Advantages
    a) Possibility of an out of synchronism automatic reclose is eliminated
    b) The dead time is not extended
2) Disadvantages
    a) A dedicated feeder 3 phase VT is required. This requires space in the substation and, depending on communications costs for option 1 & 2, may not be economically feasible.

[91] SCADA substations and terminals with RTUs having control function

14.8.2.4 Sync Check

1) Advantages

    a) Possibility of an out of synchronism automatic reclose is eliminated

    b) The dead time is not extended

2) Disadvantages

    a) A dedicated feeder 3 phase VT is required. This requires space in the substation and, depending on communications costs for option 1 & 2, may not be economically feasible

    b) A relay capable of performing sync check is required

15 Protection Grading

15.1 Introduction

15.2 Scope

15.3 Functional Requirements

15.4 Protection Grading

15.4.1 Introduction

15.4.2 Maximum Common Currents

rading a dial, ing and interco nnected ys tems

15.4.3.1 Radial Systems

15.4.3.2 Ring and Interconnected Systems

15.4.3.2.1 Simple Ring Systems

15.4.3.2.2 Complex Ring Systems

15.4.3.2.3 Simple Interconnected Systems

15.4.3.2.4 Complex interconnected systems

15.4.4 Inverse Definite Minimum Time Grading

15.4.4.1 Pickup

15.4.4.1.1 Pickup Errors

15.4.4.1.2 Negative Phase Sequence

15.4.4.2 Time Multiplier Setting

15.4.5 Grading Margins

15.4.5.1 Fixed Grading Margins

15.4.5.2 Linear Methods

15.4.5.2.1 Fixed Component

15.4.5.2.2 Variable Component

15.4.5.2.3 Major Relay Grading With a Minor Relay

15.4.5.2.4 Major Relay Grading With a Fuse

[92] Discrimination can be affected by disk integration. Refer to Appendix C – Disk Integration.

15.4.6 Total Fault Clearance Time

15.5 Appendix A – Variable and Fixed Components of Common Relays

[99] Siprotec Overcurrent Time Protection 7SJ80 V4.6 Manual

15.6 Appendix B – IDMT Characteristics

15.6.1 Equations

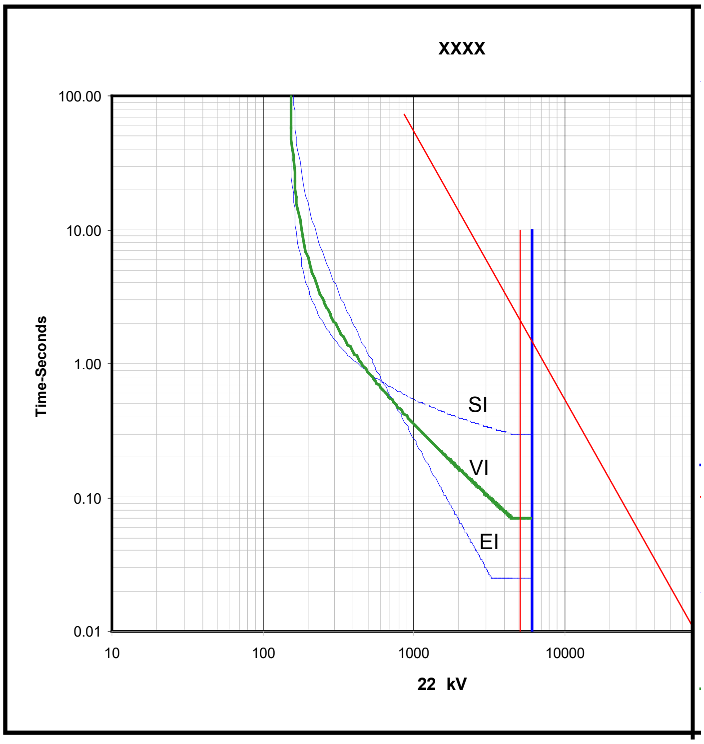
Table 15.5 lists the IEC60255 equations for inverse time characteristics

Table 15.5 – Inverse time characteristic equations

Characteristic	Equation (IEC60255)
Standard Inverse (SI)	$t = TMSx\frac{0.14}{\left(I_f/I_s\right)^{0.02} - 1}$
Very Inverse (VI)	$t = TMSx\frac{13.5}{\left(I_f/I_s\right) - 1}$
Extremely Inverse (EI)	$t = TMSx\frac{80}{\left(I_f/I_s\right)^{2} - 1}$
Long Time Standard Earth Fault	$\boldsymbol{t = TMSx\frac{120}{\left(I_f/I_s\right) - 1}}$

15.6.2 Curves

Figure 15.7 – Inverse time curves



15.7 Appendix C – Disk Integration

Electromechanical relays use a Ferraris induction disk to respond to overcurrent [100]. The current coil magnetises the part of the relay's electromagnetic yoke above directly below the disk. The part below the disk is delayed with a time lag produced by means of a shading ring. The ensuing phase displacement between the two fluxes causes the disk to rotate. The torque produced by the fault current determines the speed of rotation of the disk. To prevent the disk from rotating continuously, its motion is opposed by a spring.

Fixed to the disk shaft is a moving contact which rotates toward a fixed contact attached to the relay frame. When the moving contact reaches the fixed contact, it initiates tripping. The time multiplier setting (TMS) on the disk determines the distance the moving contact has to travel to reach the fixed contact. Once the CB has tripped, the fault current falls to zero and the spring forces the disk to return to its rest (I = 0) position.

The initial spring tension is adjusted so that the disk just starts to move (observed through a microscope) at a nominal 1.05 pu of the relay plug setting. When a 1.00 TMS is applied, the reset time following a trip is adjusted to 9.00 seconds by means of a braking magnet. This is a C – shaped permanent magnet mounted with the disk in its air gap. It can be adjusted radially relative to the disk. When the disk moves in this magnetic field, direct currents are induced in it which will produce flux to oppose the movement (Lenz's Law). The further out the magnet is set, the greater the opposing torque and hence the longer the disk will take to reset [101].

The current in the major relay does not always fall to zero following a trip. An example is a feeder (major) relay with two Y-split reclosers (minor relays). When one of the Y-split reclosers trips the feeder relay will carry the load current of the other Y-split. The load current in the major relay will tend to oppose the spring's torque, slowing the reset time. This effect can be even more significant where the major relay is the transformer LV. The load current following the recloser trip might only be a sixth or eighth of its total load, which could increase the reset time from 9 seconds to as much as 30 seconds for a 1.00 TMS.

Disk integration is associated with feeder auto-reclose. If the major relay's disk reset time exceeds the recloser dead time, its starting position at reclosure will not be its rest position. This means that the relay's TMS is effectively reduced. Thus, if the fault persists, it will operate faster than intended, with the consequent loss of discrimination. This failure to reset to its rest position is described as disk integration. Progressive reclosures reduce the effective TMS (i.e. reduce the distance the moving contact has to travel to initiate a trip).

This phenomenon was particularly common with the old, hydraulic reclosers. Their dead time was determined by means of a dashpot (i.e. an oil filled cylinder with a small hole in its base). A spring was released as the recloser tripped, driving a piston to force the oil out of the cylinder. When all of the oil was expelled, a moving contact attached to the piston would energise the recloser's closing coil.

The problem was that the slowest dead time thus achieved was typically 4 – 5 seconds. This would be on a cold morning when the oil was viscous. On a hot day, the oil would be thin, providing a dead time on the order of a second. These short dead times cause significant loss of discrimination between feeder CBs and reclosers and also between transformer and feeder CBs.

Numerical technology and the proliferation of numerical relays and reclosers have led to the demise of hydraulic reclosers. Numerical timers vary with temperature in parts per million. All of the numerical relays

[100] A household kWhr meter is similar however a voltage and a current coil are used to produce a turning torque on the disk.

[101] The permanent magnet is adjusted during maintenance. With age, the magnet looses its magnetism and cannot be adjusted to meet the relay specifications. This causes the relay to operate faster. Loss of discrimination is therefore the primary reason to replace electromechanical relays.

on the Western Power system are all set to reset instantaneously once the current falls below about 0.95 I_{SET}. The disk relays are still in service without disk integration problems. The now reliable 5 second autoreclose dead time has eliminated the discrimination problem.

The most likely cause of disk integration today would involve feeder earth fault relays on SWER systems. Any SWER unbalance on the feeder would appear as load to such a relay. Thus, if a single phase spur's recloser tripped and reclosed, the feeder's earth fault relay's reset time could be significantly increased. The effect is exacerbated by multiple recloses and slow feeder earth fault TMS.

The solution with modern reclosers is simply to increase the dead time (not very practical with the hydraulic reclosers) and / or to try to balance the spurs. With the old reclosers, the solution was to replace the offending disk relay with a numerical relay [102].

[102] Numerical relays preceded numerical reclosers by around ten years.

16 Protection Sensitivity

16.1 Introduction

The Technical Rules require but do not define the meaning of the term 'sufficiently sensitive'. This section defines the errors and risks which must be considered to ensure a protection system meets the 'sufficiently sensitive' requirement.

Sensitivity is fundamentally a Technical Rules compliance issue. Western Power accepts accountability for managing Technical Rules compliance issues and to:

1) Be aware of Technical Rules compliance issues
2) Implement corrective measures

16.2 Scope

This section applies to all Western Power transmission and distribution circuits.

16.3 Specific Compliance Requirements

16.3.1 Technical Rules Requirements

The Technical Rules require that:

1) Protection schemes must be sufficiently sensitive to detect fault currents in the primary equipment taking into account the errors in protection apparatus and primary equipment parameters under the system conditions in clause 2.9.6 [103].
2) Under minimum and maximum system conditions, all protection schemes must detect and discriminate for all primary equipment faults within their intended normal operating zones [104].
3) For abnormal equipment conditions involving two primary equipment outages, all primary equipment faults must be detected by one protection scheme and be cleared by a protection system. Back-up protection systems may be relied on for this purpose. Fault clearance times are not defined under these conditions [105].

16.4 Functional Requirements

16.4.1 Normal Operating State

Normal Operating State is when all significant elements of the transmission system are in service with either minimum or maximum generation. All protection systems must be sensitive enough to detect faults in their operating zone.

16.4.2 Minimum System Condition [106]

Minimum condition is characterized by:

[103] Technical Rules clause 2.9.6.(a)
[104] Technical Rules clause 2.9.6.(b)
[105] Technical Rules clause 2.9.6.(c)
[106] Technical Rules Attachment 1 Glossary

1) The least number of generating units normally connected at times of minimum generation.
2) There is one primary equipment outage [107] which, in combination with the minimum generation, leads to the lowest fault current at the particular location for the fault type under consideration.

All protection systems must be sensitive enough to detect faults up to the next downstream protection system or at the feeder end.

16.4.3 Abnormal Equipment Condition [108]

Abnormal Equipment Conditions result in the lowest fault levels to be detected. Abnormal equipment conditions are characterized by:

1) The number of generating units connected to the power system is the least number normally connected at times of minimum generation.
2) There is one worst case Generating unit outage. That is, a unit is unavailable that would otherwise be part of the normal minimum generation pattern. This unit is replaced by another of lower priority in the generation dispatch schedule. The new unit chosen must result in a credible generating pattern. The generating pattern must, when combined with the outages in item 3, lead to the lowest fault current at the particular location of interest.

   This has a larger impact on the transmission system when the fault is located close to the optimum dispatch generator. For example, replacing a Kwinana generator with a Muja generator will have significant impact on transmission fault levels at Kwinana. Replacing the same generators will have less impact on the distribution system or transmission faults distant from Kwinana.
3) There are either:
   a) No more than two primary equipment outages.

      Under these conditions all secondary equipment is in place. The following is an example of how the protection systems must perform with two primary outages:

      i) A line and the lowest impedance transformer are out of service. The feeder main protection system is required to detect faults up to and including the first recloser. The feeder second protection system is required to detect faults up to and including the first recloser if the main protection system does not include circuit breaker failure. The first recloser is required to detect faults up to and including the second recloser. The second recloser is required to detect faults up to the feeder end.
   b) No more than one primary equipment outage and no more than one secondary equipment outage.

      The following are examples of how the protection systems must perform with one primary outage and various secondary equipment outages:

      i) Feeder main protection out of service: The feeder second protection system must detect faults up to and including the first recloser.
      ii) First recloser out of service: The feeder main protection system must detect faults up to and including the second recloser.

[107] The Technical Rules define an outage as a planned or unplanned unavailability of equipment.

[108] Technical Rules Attachment 1 Glossary

iii) Second recloser out of service: The first recloser must detect faults up to the feeder end.

iv) Third recloser out of service. The second recloser must detect faults up to the feeder end.

16.5 Overcurrent Sensitivity

16.5.1 Overview

16.6 Performance

16.6.1.1 Protection Sensitivity Factor – Target (K_{PSFT})

16.6.1.2 Protection Sensitivity Factor - Calculated (K_{PSFC})

16.6.1.3.1 Example

16.6.2 K_{PSFT} =

16.6.3.1 Errors

16.6.3.1.1 Relay Errors

16.6.3.1.1.1 Electromechanical Relays

16.6.3.1.1.2 Numerical Relays

16.6.3.1.2 Current Transformer Errors

16.6.3.1.2.1 P Class CT

16.6.3.1.2.2 PX Class CT

16.6.3.1.3 Plant Parameter Errors

16.6.3.1.4 Calculation Errors

16.6.3.1.5 Summary of Errors

16.6.3.2 Risks

16.6.3.2.1 TPES Data Quality Risk

16.6.3.2.2 Load Modelling Risk

16.6.3.2.3 System Configuration Risk

16.6.3.2.4 Fault Impedance Risk

16.6.3.2.4.1 Low Fault Impedance

16.6.3.2.4.2 High Fault Impedance

[109] The engineer must decide the worst case fault type and consider the nature of the element they are setting (i.e. phase, NPS, EF, SEF, etc)
[110] Historically distribution planning have also accepted a K_{PSFT} = 0.7 .
[111] "Hard To Find Information About Distribution Systems", by ABB (DM # 7168193)
[112] Note that negative phase sequence is generally set higher that the earth fault pickup so unbalance should not be an issue.
[113] Historically, Western Power has applied an absolute maximum earth POC of 60 A.

16.6.3.2.6 Safety Margin

16.6.3.2.7 Summary of Risks

16.6.3.3 K_{PSFT} = Required

16.6.4 Remedial Measures When P_{SP} < 0%

16.6.4.1 Enable Negative Phase Sequence

16.6.4.2 Modify Existing Settings

16.6.4.2.1 Single Phase Systems

16.6.4.3 Numerical Relay

16.6.4.4 Add a Back-up Protection system

16.6.4.5 Recloser Location

16.6.4.6 Load Encroachment

16.6.4.7 De-rate the Transformer

16.6.5 Managing a P_{SP} < 0%

16.6.5.1 Distribution Engineer's Responsibility

16.6.5.2 Protection Engineer's Responsibility

16.7 Protection Sensitivity - Transmission System

16.7.1 Fault Detection

16.7.1.1 Differential Element

16.7.1.2 Distance Element

16.7.1.3 Overcurrent Element

16.7.1.3.1 Non-interlocked Directional Earth Fault

16.7.1.3.2 Interlocked Directional Earth Fault Comparison

16.7.2 High Impedance Faults

16.7.3 Weak Infeed

16.7.4 Design Options

16.8 Appendix A – IDMT Curves

16.8.1 Electromechanical Relays

16.8.1.1 Errors

16.8.2 Numerical Relay

16.8.2.1 Errors

16.9 Appendix B – Single Phase System

16.10 Appendix C – Effect of Tap Changer

16.10.1 Discussion

16.11 Appendix D – Fuses

16.11.1 Drop Out Fuses

16.11.2 High Rupture Capacity Fuses (HRC)

16.12 Appendix E – Rules of Thumb

16.12.1 Single Conductor Circuits

16.12.2 Bundled Conductors

16.12.3 Cables and Aerial Bundled Conductors

17 Selecting Instrument Transformers

17.1 Introduction

17.2 Scope

17.3 Specific Compliance Requirements

17.3.1 Relevant Australian Standards

17.4 Functional Requirements

17.5 Transformer Fundamentals

17.5.1 Conventions

17.5.1.1 Current Transformers

17.5.1.2 Interposing Current Transformers

17.5.1.3 Voltages Transformers

17.5.2 Performance Specification Relationships

17.5.2.1 Current Transformers

17.5.2.1.1 M Class

17.5.2.1.2 P Class

17.5.2.1.4 PX Class

[114] Previously this performance would have been specified as 5P300F30

17.5.2.2 Interposing Current Transformers

17.5.2.2.1 M Class

17.5.2.2.2 PX Class

17.5.3 Magnetising Current

17.5.4 Knee Point Voltage

17.5.5 Remanence

[115] Wikipedia

17.6.1 Design Requirements

17.6.1.1 CT Earthing

17.6.1.2 Tap Ratio

17.6.1.3 Busbar Protection

17.6.2 Specification Requirements

17.6.2.1 M Class

17.6.2.2 P Class

17.6.2.2.1 Rated Output

17.6.2.2.2 Accuracy Class

17.6.2.2.3 Accuracy Limit Factor

17.6.2.3 PR Class

17.6.2.4 PX Class

17.6.2.4.1 Ratio

17.6.2.4.2 Magnetising Current

17.6.2.4.3 Knee Point Voltage

17.6.2.4.3.2 Reliability

17.6.2.4.4 Secondary Burden

17.6.2.4.5 Thermal Rating

17.6.2.4.5.1 Continuous Rating

17.6.2.4.5.2 Short Time Rating

17.7 Interposing Current Transformers

17.7.1 Design Requirements

17.7.1.1 Transformer Differential Schemes

17.7.1.1.1 Star / Delta IPCT

17.7.1.1.3 HV Restricted Earth Fault

17.7.1.2 Busbar Protection

17.7.2 Specification Requirements

17.7.2.1 Ratio

[116] Joe Mooney, Distance Element Performance Under Conditions of CT Saturation, Schweitzer Engineering Laboratories, 2007, p1.

[117] $R_{40} = [R_{20} \times (235 + 40)] / (235 + 20)$

[118] The older main CTs had a ratio 150 / 0.577 with the secondaries connected in delta to yield an output of 1 A. The delta winding filters the zero sequence currents to meet requirements of relays such as the 42C1 and D21SE. The delta winding also provides a 30° phase shift to compensate for that of the power transformer secondary. While the D21SE is now obsolete and would be replaced with a numerical relay, the 42C1 is still reliable and is not normally replaced.

17.7.2.1.1 Transformer Differential Scheme

17.7.2.2 Magnetising Current

17.7.2.3 Knee Point Voltage

17.7.2.4 Secondary Resistance

17.7.2.5 Thermal Ratings

17.7.2.5.1 Continuous Rating

17.7.2.5.2 Short Time Rating

[119] In Figure 7, G and H refer to the IPCT resistances and F and K refer to lead resistances.

17.8 Voltage Transformers

17.8.1 Design Requirements

17.8.1.1 VT Earthing

17.8.1.2 Secondary Burden

17.8.1.2.1 Shunt Resistors

17.8.2 Specification Requirements

17.8.2.1 Inductive VTs

17.8.2.1.1 Rated Primary Voltage

17.8.2.1.2 Rated Secondary Voltage

17.8.2.1.3 Rated Output

17.8.2.1.4 Accuracy Class

17.8.2.1.5 Rated Voltage Factor

17.8.2.2 Additional Specification Requirements for Capacitive VTs

17.8.2.2.1 Transient Response

17.9 Appendix A – Transient Analysis

17.10 Appendix B – Zero Sequence Filtering

17.10.1 IPCT Required

17.10.2 IPCT Not Required

17.11 Appendix C – IPCT Ratio Effect on Transformer Bias Setting

[121] Manufacturer recommendation

17.11.1 Example of a Ratio Adjusted IPCT

17.11.2 Example of a Ratio Not Adjusted IPCT

18 Transformer Sequence Networks and Fault Currents

18.1 Scope

This section derives the phase currents from sequence currents for LV faults on transformers used on the Western Power system. It is intended to be a basis for design engineers to verify current distributions for various combinations of transformers. It can also be used to verify modelling and field results.

18.2 Introduction

18.2.1 General

18.2.1.1 Fault Configurations

The following fault configurations are examined:

1) Bolted 3 phase fault

2) Bolted fault between b and c phase

3) Bolted fault between a phase and earth

Down-stream impedances are ignored (fault is very close to LV busbar) and load current is not included.

The calculations in this document are done in per unit (refer to Section 18.13).

18.2.1.2 Equations

The following equations are used to simplify the sequence current equations (refer to Section 18.12 for a list of common notation):

$$Z^* = Z_{1S} + Z_{1H} + Z_{1L}$$

$$Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$$

$$Z^{***} = 2(Z_{1S} + Z_{1H} + Z_{1L}) + Z_{0L} + \left(\frac{Z_{0T}(Z_{0S} + Z_{0H})}{Z_{0S} + Z_{0H} + Z_{0T}}\right)$$

18.2.1.2.1 Star Connected Winding

$$I_{\text{Line}} = I_{\text{Phase}}$$

$$V_{\text{Line}}\angle\varphi = \sqrt{3}V_{\text{Phase}}\angle\varphi \pm 30°$$

18.2.1.2.2 Delta Connected Winding

$$I_{Line}\angle\varphi = \sqrt{3}I_{Phase}\angle\varphi \pm 30°$$

$$V_{\text{Line}} = V_{\text{Phase}}$$

18.2.1.2.3 Phase – Phase Fault Level

$\left|I_{\text{ph\_ph}}\right| = \frac{\sqrt{3}}{2}\left|I_{3\text{ph}}\right|$ is derived from the sequence networks:

$$I_1 = -I_2 = \frac{1\angle 0°}{Z_1 + Z_2}$$

$$I_{3\text{ph}} = a^2 I_1 = \frac{1\angle - 120°}{Z_1}$$

$$I_{\text{ph\_ph}} = a^2 I_1 - \text{a}I_2 = \frac{\sqrt{3}\angle{-90°}}{Z_1+Z_2}, \text{(using}a^2 - a = -j\sqrt{3})$$

$$\left|I_{\text{b\_ph-ph}}\right| = \left|\frac{\sqrt{3}\angle{-90}}{Z_1+Z_2}\right| = \frac{\sqrt{3}}{2}\left|I_{\text{b\_3ph}}\right|, (Z_1 = Z_2)$$

Refer to Section 18.11 for a diagrammatic representation of the ‘a’ operator.

18.2.1.3 Vector Representation

The vector representation of a transformer describes the number of windings and their interconnection. The order of the representation is:

1) HV winding with, if any, earthing
2) If an autotransformer an ‘a0’ designates that it is an autotransformer with no phase shift.
3) Tertiary winding with phase shift (i.e. d11 is Western Powers standard delta winding)
4) LV winding with, if any, earthing
5) Earthing transformers with no auxiliary windings for load are represented as ‘zn’. If there is an auxiliary winding then the representation will be either a ‘zn1’ or ‘zn11’.

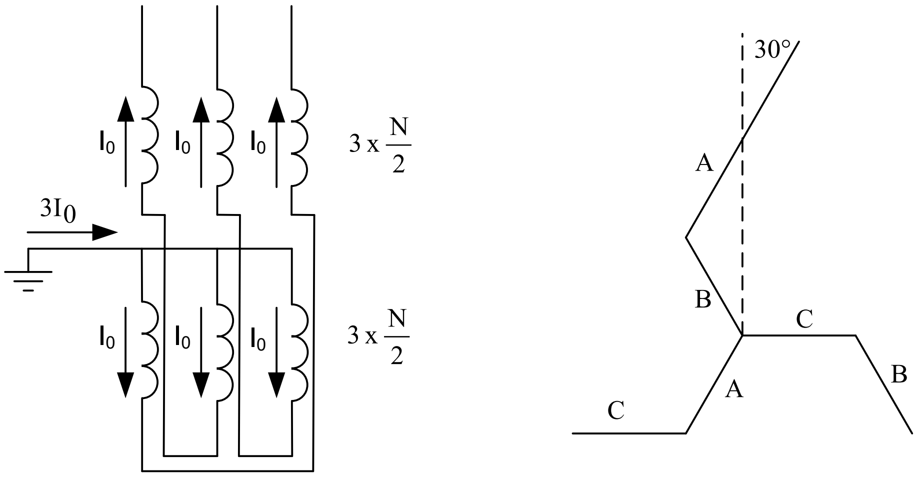
As an example the 490 MVA autotransformer vector representation is YNa0d11 + zn1. The HV/LV is earthed, there is a d11 tertiary winding and a zn1 earthing transformer (with auxiliary winding).

18.2.2 Earthing Transformers

Earthing transformers are used to provide a zero sequence path to the zero sequence bus. They are typically used when the LV winding is an unearthed star or a delta winding.

Earthing transformers are configured in a zigzag arrangement which automatically equalizes the zero sequence flux in each core. This occurs because each core has two equal windings which have opposite currents. Figure 4.2.1 shows the current distribution in an earth transformer and a zn1 vector grouping.

Figure 18.1 – Earthing transformer current distribution (zn1)



18.2.3 Ampere Turns Balance

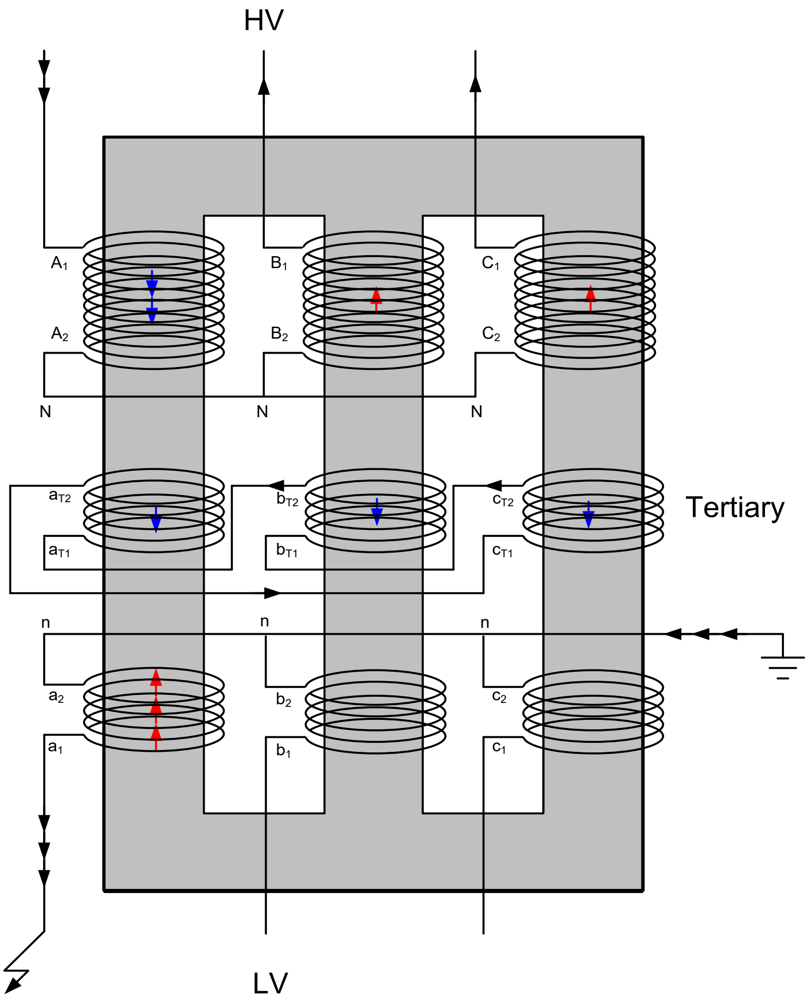
18.2.3.1 Tertiary Windings

Tertiary windings are used to:

Provide a zero sequence current path. Tertiary winding are interconnected in a delta configuration as shown in Figure 18.2.

1) Earth fault current flowing in the earthed LV star winding produces flux in the core. The flux resulting from the earth fault current produces zero sequence currents in the tertiary winding. The zero sequence currents flowing in the tertiary winding produce zero sequence flux in the core. The zero sequence flux opposes the flux resulting from the earth fault current (Lenz's law). Any flux unbalance in each phase of the core is cancelled by the 2-1-1 phase currents in the unearthed HV star winding.
2) Capacitors, reactors, station supplies or generators can be connected to tertiary windings.

Figure 18.2 – Earth fault on transformer with tertiary winding. Ampere turns in each phase are balanced so the transformer core does not saturate.



18.2.3.2 Tank Delta

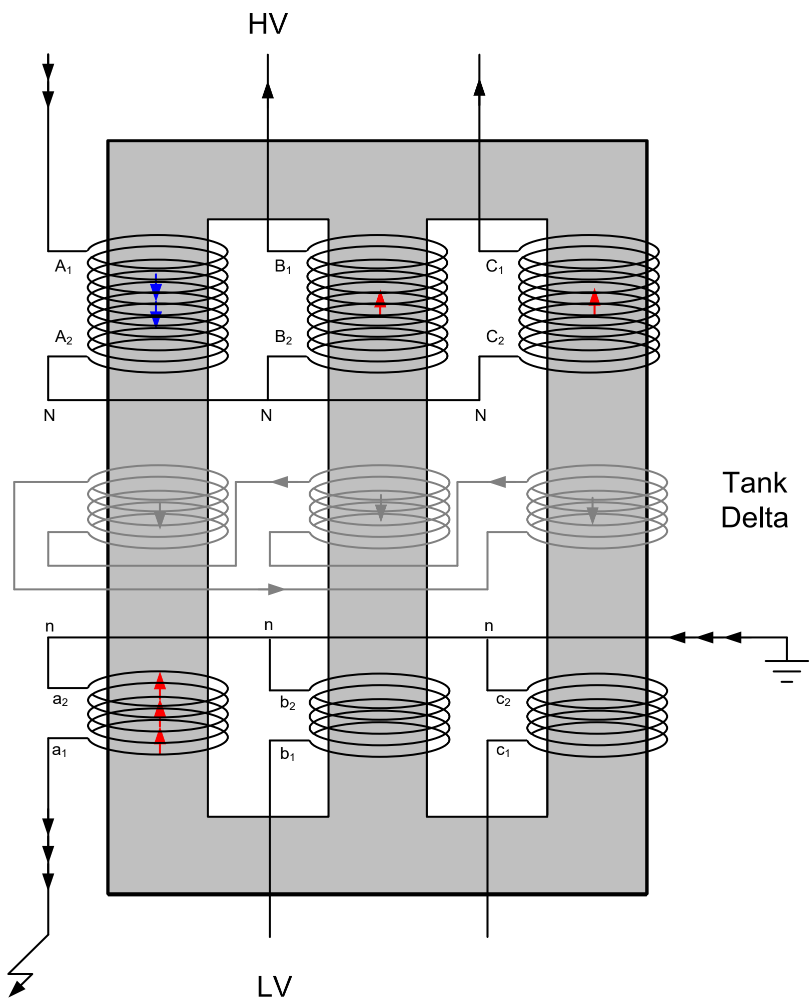
In addition to the tertiary winding, zero sequence flux also flows between the core and the transformer tank. This effectively forms a tank delta zero sequence impedance ($Z_{0\_Tank\ Delta}$) which is in parallel with the tertiary winding zero sequence impedance.

The tank delta zero sequence impedance is typically 75% to 300% of the transformer positive sequence impedance. As an example, given a 10 MVA transformer with Z_{1HL} = 7.72% the tank delta is impedance is 5.79% ≤ $Z_{0\_Tank\ Delta}$ ≤ 23.16%. Because of the tank delta, zero sequence currents flow in the LV winding even when a tertiary winding (Z_{0T}) or an earthing transformer is not present. Tank deltas are not relied on to provide a zero sequence path because:

The current flowing between the core and tank causes the tank to radiate which can interfere with communications.

It is expensive to have the manufacturer size the tank to provide a defined maximum tank delta impedance. If the tank delta impedance is too high, the fault current may be too low. Figure 18.3 demonstrates that a tank delta still provides a 2-1-1 split on the HV windings.

Figure 18.3 – Earth fault on transformer without tertiary winding



18.2.3.3 Turns Ratio

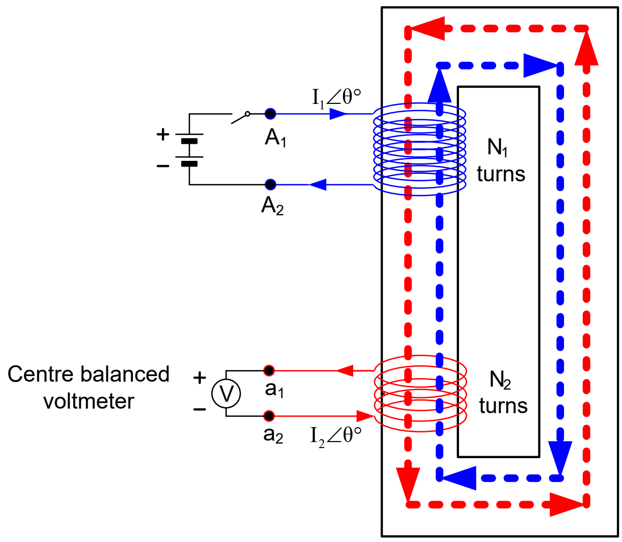
To prevent core saturation the ampere turns on a core must sum to zero:

$I_1N_1 = I_2N_2$ therefore $N_1 / N_2 = I_2 / I_1 = n$

To balance the ampere turns, the flux created by the current in the HV winding induces an opposing current in the LV winding. The standard convention used in this document is that a positive current flowing into A_1 and out of A_2 produces a current flowing out of a_1 and into a_2.

A 'flick' test shown in Figure 18.4 verifies the Terminals markings and current flow. A battery positive is connected via a switch to A_1 and negative to A_2. A balanced voltmeter positive is connected to a_1 and negative to a_2. When the battery positive is applied to Terminals A_1, the voltmeter deflects positive. When it is removed the voltmeter deflects negative (Lenz's law).

Figure 18.4 – Single phase transformer



$$I_1N_1 = I_2N_2$$
$$V_2N_1 = V_1N_2$$

18.2.3.3.1 Turns Ratio in a Single Phase System

The turn's ratio, n, is used to balance the ampere turns between the LV and HV windings. For the single phase transformer shown in figure 4.4.1.1 the turns ratio is defined by the following equation:

$$\text{Turns Ratio} = n = \frac{V_{1\_phase}}{V_{2\_phase}} = \frac{I_{2\_phase}}{I_{1\_phase}} = \frac{N_1}{N_2}$$

Where I1, N1 and V1 refer to the primary side and I2, N2 and V2 refer to the secondary side.

To transform a current at a lower voltage to a current at a higher voltage, divide the LV current by the turns ratio.

$$I_1N_1 = I_2N_2 \therefore I_1 = I_2\frac{N_2}{N_1} = \frac{I_2}{n}$$

To transform a current at a higher voltage to a current at a lower voltage, multiply the HV current by the turns ratio.

$$I_1 N_1 = I_2 N_2 \therefore I_2 = I_1 \frac{N_1}{N_2} = nI_1$$

18.2.3.3.2 Turns Ratios in Three Phase Systems

Convention dictates that three phase systems are described by their line voltages (i.e. $V_{L\text{-}L}$) and line currents. Conversely, all transformer action in a three phase system takes place on a per phase basis. The HV and LV windings of each phase are wound onto the same limb of the transformer core. The windings therefore produce phase currents and voltages. The phase windings determine the line currents and voltages in the three phase system. The actual turns ratio accounts for the transformation from phase currents and voltages to line currents and voltages.

Tap positions are always described by their line voltages, but they are spaced according to their phase voltages (i.e. by $V_{L\text{-}L}$ / √3 for star windings).

18.2.3.3.2.1 Star / Star Actual Turns Ratio

In a star connected system V_{line} = √3 V_{phase}.

$$\text{Turns Ratio } = n = \frac{\frac{V_{1\_\text{line}}}{\sqrt{3}}}{\frac{V_{2\_\text{line}}}{\sqrt{3}}} = \frac{V_{1\_\text{phase}}}{V_{2\_\text{phase}}} \Rightarrow Actual \text{ Turns Ratio} = n$$

18.2.3.3.2.2 Star / Delta Actual Turns Ratio

In a star connected system V_{line} = √3 V_{phase}. In a delta connected system V_{line} = V_{phase}. The HV line voltage must be converted to a phase voltage by dividing by √3. The actual turns ratio is therefore created by dividing the turns ratio by a factor of √3.

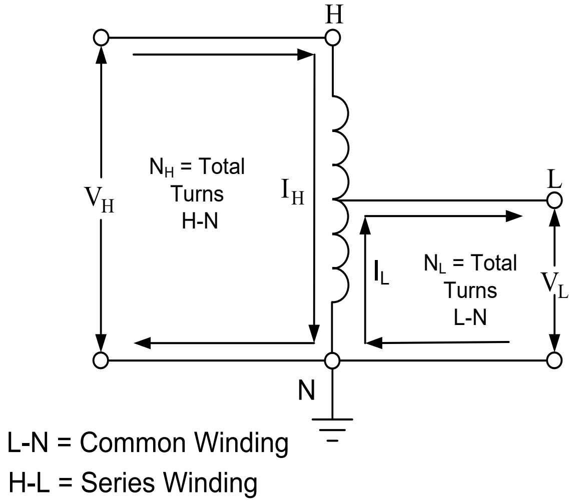
$$\text{Turns Ratio} = n = \frac{\frac{V_{1\_\text{line}}}{\sqrt{3}}}{V_{2\_\text{phase}}} = \frac{1}{\sqrt{3}} \frac{V_{2\_\text{phase}}}{V_{1\_\text{line}}} \Rightarrow Actual \text{ Turns Ratio} = \frac{n}{\sqrt{3}}$$

18.2.3.3.2.3 Delta / Star Actual Turns Ratio

In a star connected system V_{line} = √3 V_{phase}. In a delta connected system V_{line} = V_{phase}. The LV line voltage must be converted to a phase voltage by dividing by √3. The actual turns ratio is therefore created by multiplying the turns ratio by a factor of √3.

$$\text{Turns Ratio} = n = \frac{V_{1\_\text{Line}}}{\frac{V_{2\_\text{Phase}}}{\sqrt{3}}} = \sqrt{3} \frac{V_{2\_\text{phase}}}{V_{1\_\text{line}}} \Rightarrow Actual \text{ Turns Ratio} = \sqrt{3}n$$

18.2.4 Autotransformers



$I_H N_H = I_L N_L$ therefore $I_L = I_H \frac{N_H}{N_L} > I_H \therefore N_H > N_L$

Common winding current = $I_L - I_H$

$$n = \frac{I_H}{I_L} = \frac{N_H}{N_L} = \frac{V_L}{V_H}$$

18.2.5 Delta Winding Vector Groups

Depending on how the windings are terminated, a delta winding can have either a vector grouping of d11 (11 o'clock) or d1 (1 o'clock). The vector grouping is defined by the relationship between the HV and LV reference phase voltage. With a vector grouping of d11 the a-n LV voltage leads the A-N HV voltage by 300. With a vector grouping of d1 the a-n LV voltage lags the A-N HV voltage by 300. Western Power typically uses vector group d11.

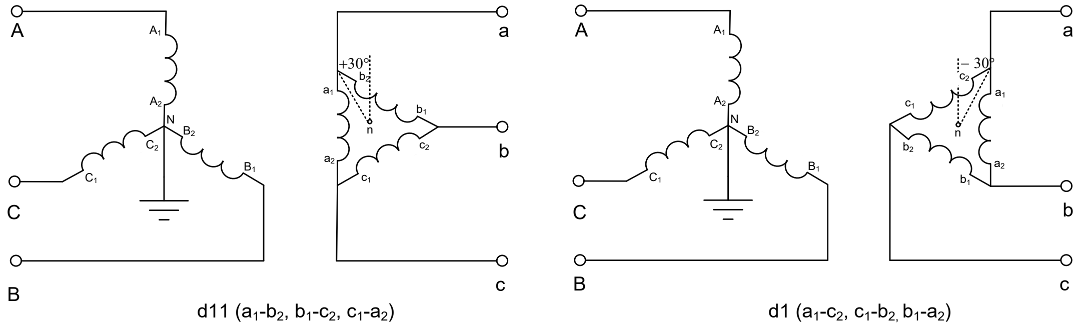
1) YNd11

   Figure 18.5 shows how connecting the delta Terminals in the following sequence produce an $+30^0$ (lead) phase shift in the a-n LV neutral voltage:

2) YNd1

   Figure 18.5 shows how connecting the delta Terminals in the following sequence produce an -30^0 (lag) phase shift in the a-n LV neutral voltage.

Figure 18.5 – d11 and d1 vector groups



18.2.6 Process

The process of determining the phase currents from the sequence networks consists of four steps:

1) Draw the sequence network
2) Determine the sequence currents
3) Determine the phase currents
4) Draw the phase current diagram

18.2.6.1 Draw the Sequence Network

18.2.6.1.1 Positive Sequence

The generator is connected in the positive sequence network.

Any phase shift between star and delta windings is shown on the positive sequence network.

If the tertiary winding is not brought out, the tertiary Terminals does not exist. On some star – delta – star transformers at some Terminals yards the tertiary is brought out to supply capacitors or reactors.

18.2.6.1.2 Negative Sequence

If the tertiary winding is not brought out, the tertiary Terminals does not exist. On some star – delta – star transformers at some Terminals yards the tertiary is brought out to supply capacitors or reactors.

Any phase shift between star and delta windings is shown on the negative sequence network.

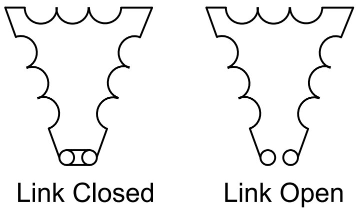
18.2.6.1.3 Zero Sequence

On some star – delta – star transformers the tertiary is brought out to supply capacitors or reactors. Because a tertiary delta winding is never connected to earth, the tertiary Terminals is not connected to the zero sequence bus directly. When the tertiary is brought out, an earthing transformer is used to connect the tertiary to the zero sequence bus. If the tertiary winding is not brought out, the tertiary Terminals does not exist.

Phase shifts do not appear on the zero sequence network.

Series and shunt links are used to show how the windings are connected to the zero bus. The rules are:

1) Series links are closed when the winding has an earthed neutral. Series links are shown as ‘A’ links in the examples below. ‘A’ links represent earth connections.
2) Shunt links are closed when the delta winding is closed and open when the delta winding is open. Shunt links are shown as ‘B’ links in the examples below. ‘B’ links represent flux equalization paths.

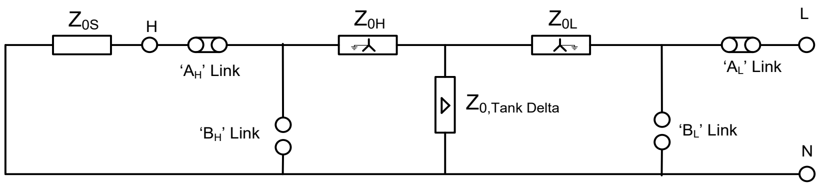


If the HV is earthed via an impedance of Z_N, it is modelled in series with the source impedance as 3 Z_N. The factor of 3 comes from the fact that the sequence networks represent I_1, I_2 and I_0. However 3I0 flows in the neutral. To correct the sequence voltages, Z_N becomes $3Z_N$ (i.e. Z_N is a single phase R or X).

18.2.6.1.3.1 Tank Delta

Figure 18.6 shows a typical tank delta in the zero sequence network.

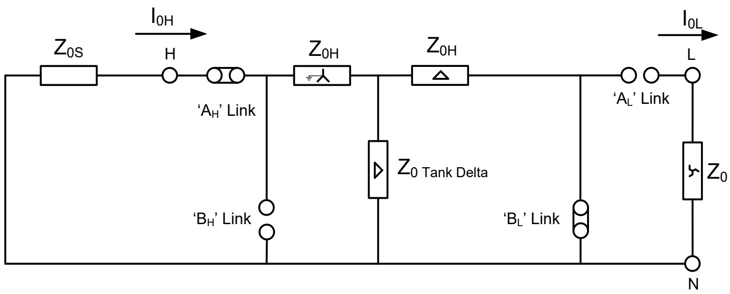
Figure 18.6 – Tank Delta



The value of a measured Z_{0T} always includes the contribution of the tank delta. The tank delta is included in the diagrams shown in this document; however it is not included in the calculations. If there is a link in the delta winding, it can be opened to measure the tank delta.

18.2.6.1.3.2 Two Winding Transformer Example

With two winding transformers there will be two 'A' links and two 'B' links. As an example, a star – delta with an earthing transformer and the HV solidly earthed would be modelled as follows:



1) The 'A_H' link is closed because the HV is earthed. The 3 Z_N impedance is absent because these transformers are solidly earthed.

2) The 'B_H' link is open because the HV winding is not a delta.

3) The 'B_L' link is closed because the LV winding is a delta.

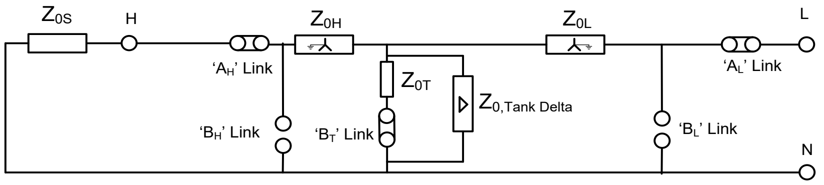
4) The 'A_L' link is open because the LV winding is not earthed.

5) The earthing transformer provides the zero sequence path and is connected externally across the LV and neutral Terminals.

6) The tank delta is shown without a link because it is always present.

18.2.6.1.3.3 Three Winding Transformer Example

With three winding transformers there are 2 series links and 3 shunt links. As an example, a star – delta – star transformer with the HV and LV solidly earthed would be modelled as follows:



1) The 'A_H' link is closed because the HV winding is earthed. The 3 Z_N impedance is absent because these transformers are solidly earthed (i.e. $Z_N = 0$).
2) The 'B_H' link is open because the HV winding is not a delta.
3) The 'B_T' link is closed because the tertiary winding is a delta.
4) The 'A_T' link is not shown because it is always open (the delta tertiary is never earthed).
5) The 'B_L' link is open because the LV winding is not a delta.
6) The 'A_L' link is closed because the LV winding is earthed.
7) The tank delta is shown in parallel with the tertiary impedance and is always connected to the zero sequence bus.
8) The tertiary is not brought out so the tertiary Terminals is not shown.

18.2.6.2 Determine the Sequence Currents

In general, $1\angle 0° = E_{ph-n}\angle 0°$. In per unit on base MVA, 'S', $E_{ph-n} = S$ and$I_1 = \frac{S}{Z_1}$. If Eph-n is off nominal (i.e. at 1.03 pu pre fault volts) Eph-n = 1.03 S and I1 = $\frac{S_{\text{off nominal}}}{Z_1}$

18.2.6.2.1 Three Phase Fault

The negative and zero sequence buses are not connected

$I_1 = \frac{1\angle 0°}{Z_1} \qquad I_2 = 0 \qquad\qquad I_0 = 0$

From Figure 18.7 it can be seen that $I_a + I_b + I_c = 0$

Figure 18.7 – Three phase fault

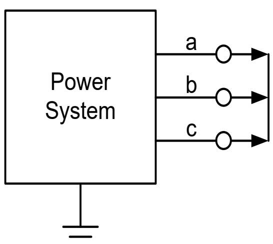
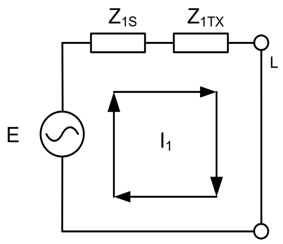


Figure 18.8 shows the relationship between the source E, Z_1, and I_1. For balanced faults $I_2 = I_0 = 0$

Figure 18.8 – Three phase fault



From sequence theory:

1) $I_a = I_1 + I_2 + I_0 = I_1$

2) $I_b = a^2 I_1 + a I_2 = a^2 I_1$

3) $I_c = a I_1 + a^2 I_2 = a I_1$

18.2.6.2.2 Phase to Phase Fault

From Figure 18.9 it can be seen that $I_a = 0$ and $I_b = -I_c$.

Figure 18.9 – phase – phase fault

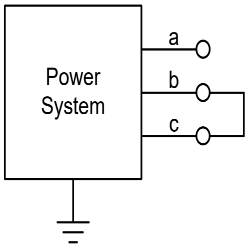
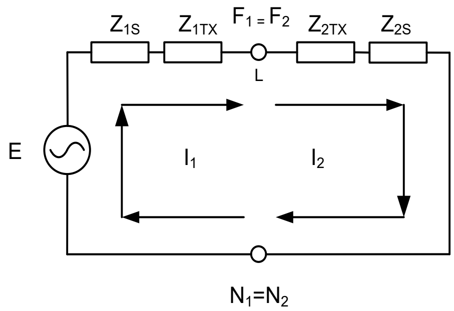


Figure 18.10 shows the relationship between the source E, Z_1, I_1, Z_2 and I_2.

Figure 18.10 – phase – phase fault



From Figure 18.10 it is seen that $I_1 = \frac{E}{Z_1+Z_2}$ and $I_2 = \frac{-E}{Z_1+Z_2}$

From sequence theory:

1) $I_a = I_1 + I_2 + I_0 = 0$, therefore $I_1 = -I_2$ (for faults clear of earth, $I_0 = 0$).

2) $I_b = a^2 I_1 + a I_2 = I_1 (a^2 – a) = -j \sqrt{3} I_1 = \frac{-j\sqrt{3}E}{Z_1+Z_2}$

3) $I_c = a\,I_1 + a^2\,I_2 = I_1\,(a - a^2) = +j\,\sqrt{3}\,I_1 = \frac{+j\sqrt{3}E}{Z_1+Z_2}$

18.2.6.2.3 Phase to Earth Fault

$$I_1 = I_2 = I_0 = \frac{E}{Z_1 + Z_2 + Z_0}$$

18.2.6.3 Determine the Phase Currents

The following equations are used to derive the phase currents:

18.2.6.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L}$$

18.2.6.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H}$$

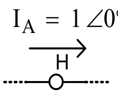
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H}$$

18.2.6.4 Draw the Phase Current Diagram

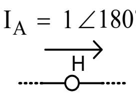
Currents are shown flowing into the HV Terminals and out of the LV Terminals. The arrow is a reference for the angle. The direction of current flow is determined by the angle.

As an example, a current of $1\angle 0°$ drawn flowing into the HV Terminals is actually flowing into the HV Terminals. A current of $1\angle 180°$ drawn flowing into the HV Terminals is actually flowing out of the HV Terminals.

In the example below, the current is flowing from left to right



In the example below, the current is flowing from right to left

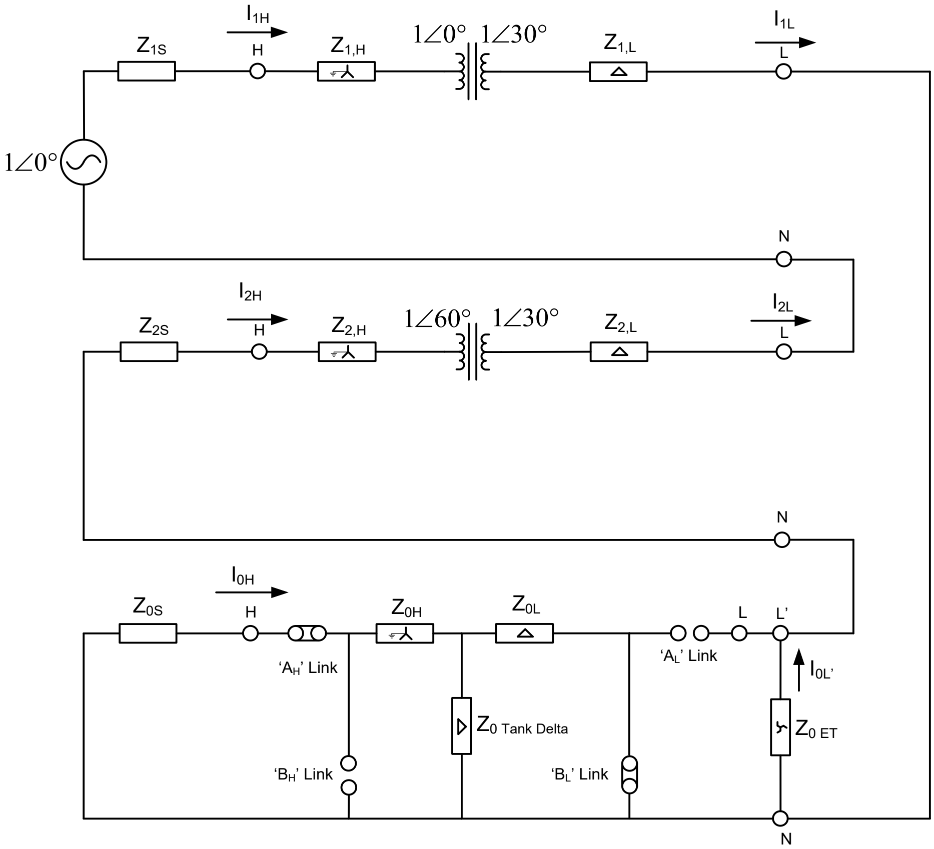


18.2.6.5 Example

Earth fault on a YNd11 + zn transformer

18.2.6.5.1 Draw the Sequence Network

The sequence network for this transformer is shown below:



There is a +30° phase shift from the star winding to a d11 delta winding in the positive sequence network. There is also a +30° phase shift from a d11 delta winding to the star winding in the negative sequence network. These phase shifts result in the negative sequence HV current leading the positive sequence HV current by 60°.

18.2.6.5.2 Determine the Sequence Currents

Define $\mathrm{Z}^{**} = Z_{1\mathrm{S}} + Z_{1\mathrm{H}} + Z_{1\mathrm{L}} + Z_{2\mathrm{S}} + Z_{2\mathrm{H}} + Z_{2\mathrm{L}}$

$I_{1\mathrm{H}} = \frac{1\angle 0°}{\mathrm{Z}^{**} + Z_{0\ \mathrm{ET}}}$ $\quad$ $I_{1\mathrm{L}} = \frac{1\angle 30°}{\mathrm{Z}^{**} + Z_{0\ \mathrm{ET}}}$

$I_{2\mathrm{H}} = \frac{1\angle 60°}{\mathrm{Z}^{**} + Z_{0\ \mathrm{ET}}}$ $\quad$ $I_{2\mathrm{L}} = \frac{1\angle 30°}{\mathrm{Z}^{**} + Z_{0\ \mathrm{ET}}}$

$I_{0\mathrm{H}} = 0$ $\quad$ $I_{0\mathrm{L}} = 0$ $\quad$ $I_{0\mathrm{L}'} = \frac{1\angle 30°}{\mathrm{Z}^{**} + Z_{0\ \mathrm{ET}}}$

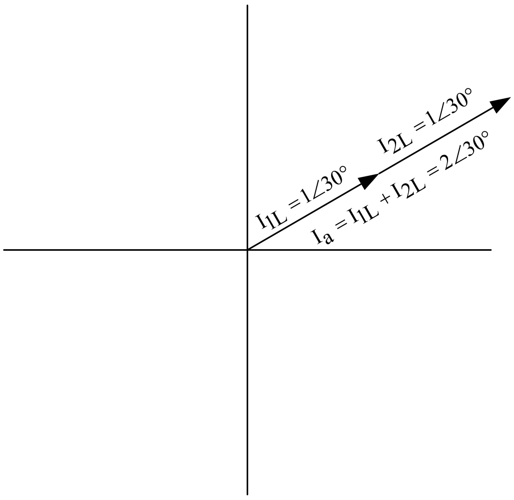
From the sequence network it can be seen that:

$I_{0\mathrm{L}'} = I_{1\mathrm{L}} = I_{2\mathrm{L}}$

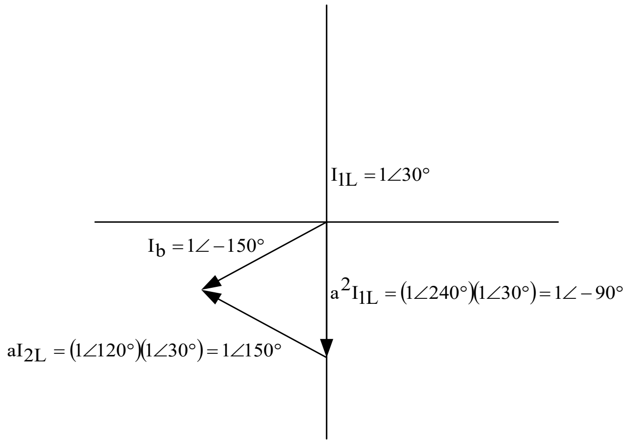
18.2.6.5.3 Determine the Phase Currents

18.2.6.5.3.1 Line Currents through the LV Terminals

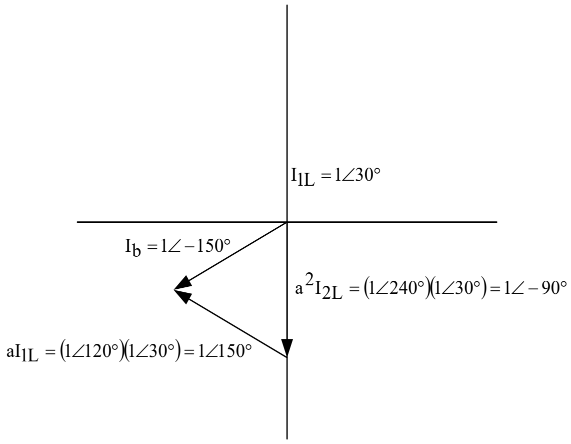
1) $I_a = I_{0\mathrm{L}} + I_{1\mathrm{L}} + I_{2\mathrm{L}} = \frac{2\angle 30°}{Z^{**} + Z_{0\ \mathrm{ET}}}$



2) $I_b = I_{0\mathrm{L}} + a^2 I_{1\mathrm{L}} + aI_{2\mathrm{L}} = \frac{(1\angle 240°)(1\angle 30°)}{Z^{**} + Z_{0\ \mathrm{ET}}} + \frac{(1\angle 120°)(1\angle 30°)}{Z^{**} + Z_{0\ \mathrm{ET}}} = \frac{(1\angle -150°)}{Z^{**} + Z_{0\ \mathrm{ET}}}$



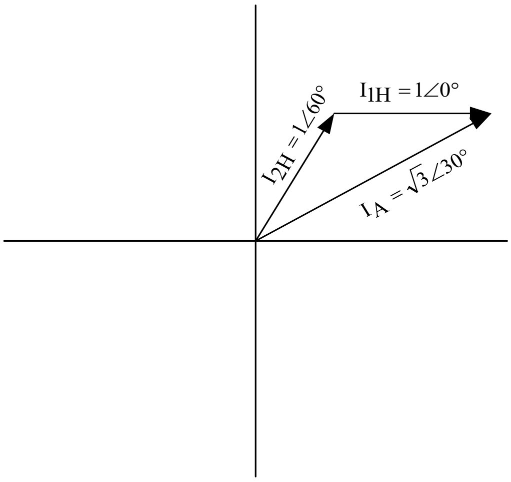
3) $I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 30°)}{Z^{**}+Z_{0\ ET}} + \frac{(1\angle 240°)(1\angle 30°)}{Z^{**}+Z_{0\ ET}} = \frac{(1\angle -150°)}{Z^{**}+Z_{0\ ET}}$



18.2.6.5.3.2 Line Currents through the HV Terminals

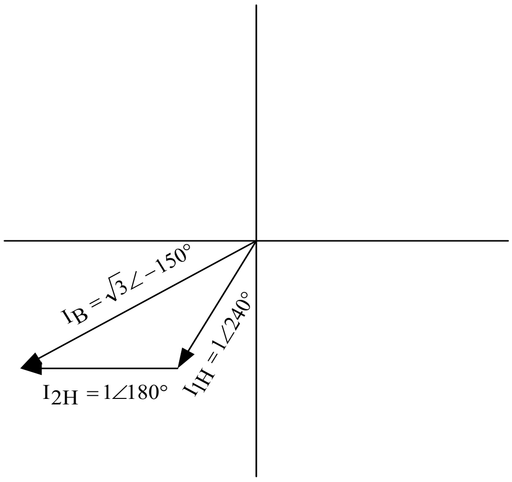
1) $I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z^{**}+Z_{0\ ET}} + \frac{1\angle 60°}{Z^{**}+Z_{0\ ET}} = \frac{\sqrt{3}\angle 30°}{Z^{**}+Z_{0\ ET}}$

The current in the LV phase winding flowing from Terminals a2 – a1 induces current in the HV phase winding from Terminals A1 – A2. This results in a current entering the HV winding from the system with an angle of 30°.

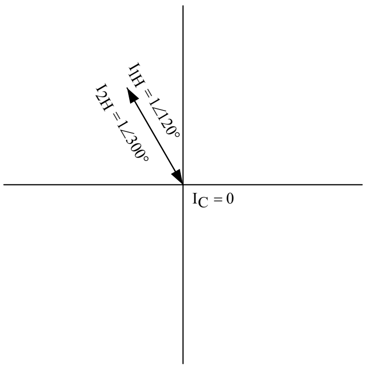


2) $I_B = I_{0H} + a^2 I_{1H} + \text{a}I_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**}+Z_{0\ \text{ET}}} + \frac{(1\angle 120°)(1\angle 60°)}{Z^{**}+Z_{0\ \text{ET}}} = \frac{\sqrt{3}\angle -150°}{Z^{**}+Z_{0\ \text{ET}}}$

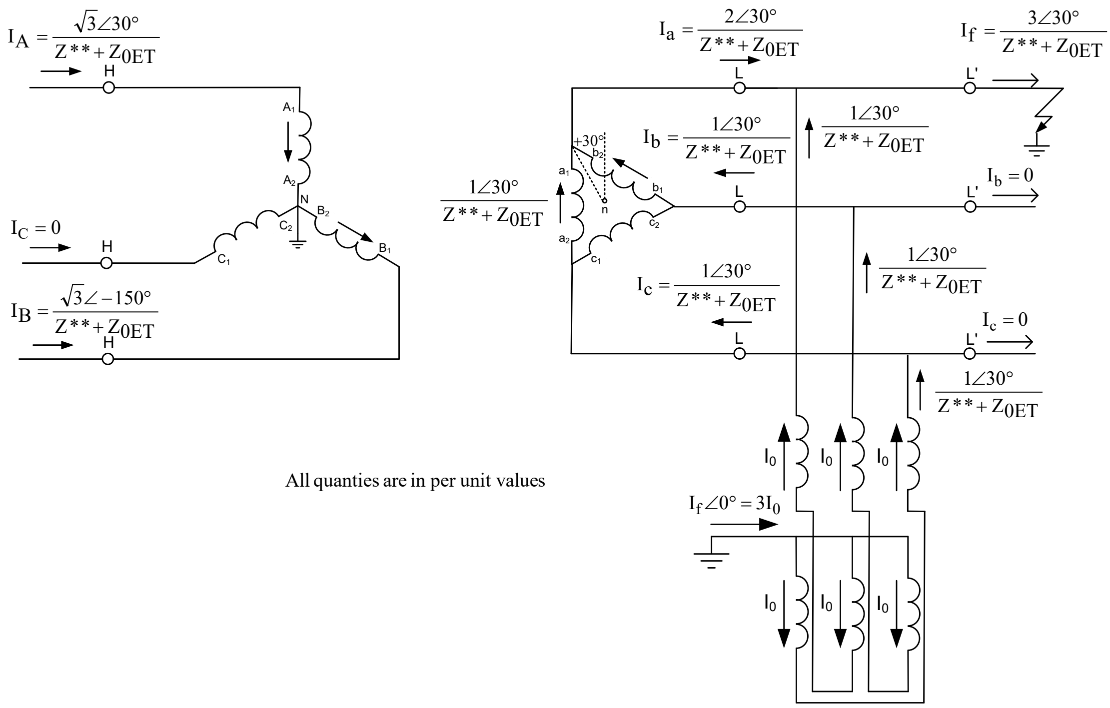
The current in the LV phase winding flowing from Terminals b1 – b2 induces current in the HV phase winding from Terminals B2 – B1. This results in a current entering the HV winding from the system with an angle of -150°.



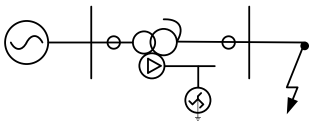
3) $I_C = I_{0H} + \text{a}I_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**}+Z_{0\ \text{ET}}} + \frac{(1\angle 240°)(1\angle 60°)}{Z^{**}+Z_{0\ \text{ET}}} = 0$



18.2.6.5.4 Draw the Phase Current Diagram

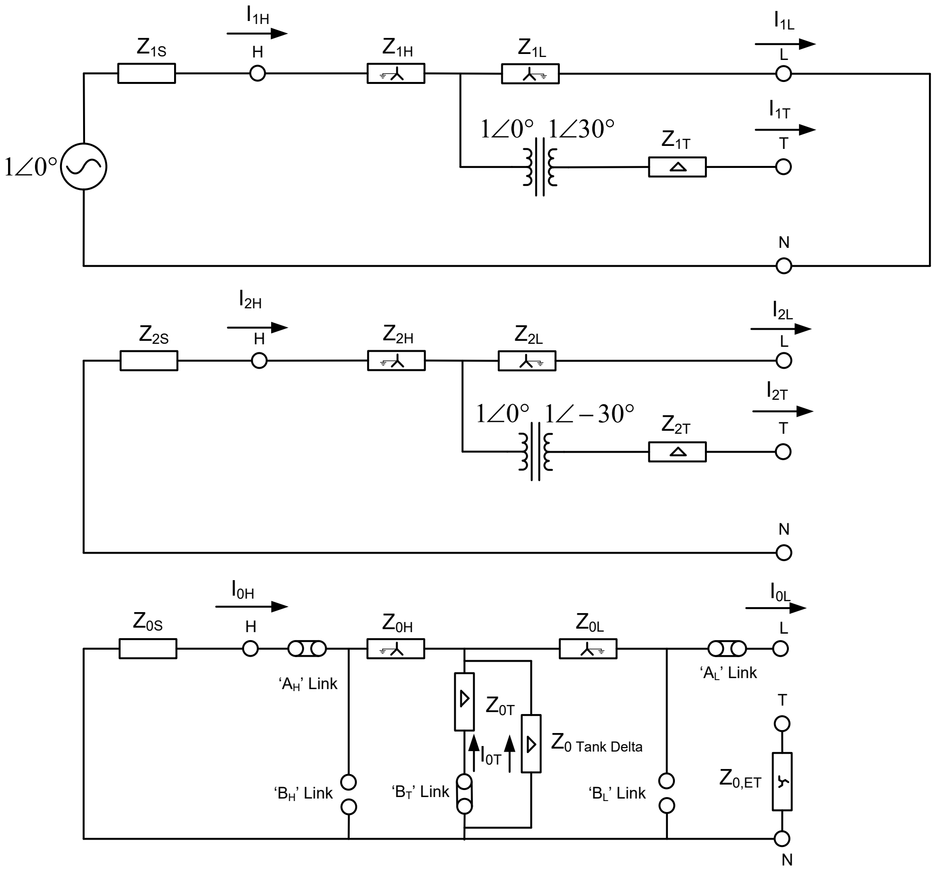


18.3 Autotransformer (Yna0d11 + zn1)



18.3.1 Three Phase LV Fault

18.3.1.1 Sequence Network



18.3.1.2 Sequence Currents

Define $Z^* = Z_{1S} + Z_{1H} + Z_{1L}$

$I_{1H} = \frac{1\angle0°}{Z^*}$ $\quad$ $I_{1L} = \frac{1\angle0°}{Z^*}$

$I_{2H} = 0$ $\quad$ $I_{2L} = 0$

$I_{0H} = 0$ $\quad$ $I_{0L} = 0$

$I_{1T} = 0$ $\quad$ $I_{2T} = 0$ $\quad$ $I_{0T} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

18.3.1.3 Phase Currents

18.3.1.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle0°}{Z^*}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle240°)(1\angle0°)}{Z^*} = \frac{1\angle-120°}{Z^*}$$

$$I_c = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{1\angle 120°}{Z*}$$

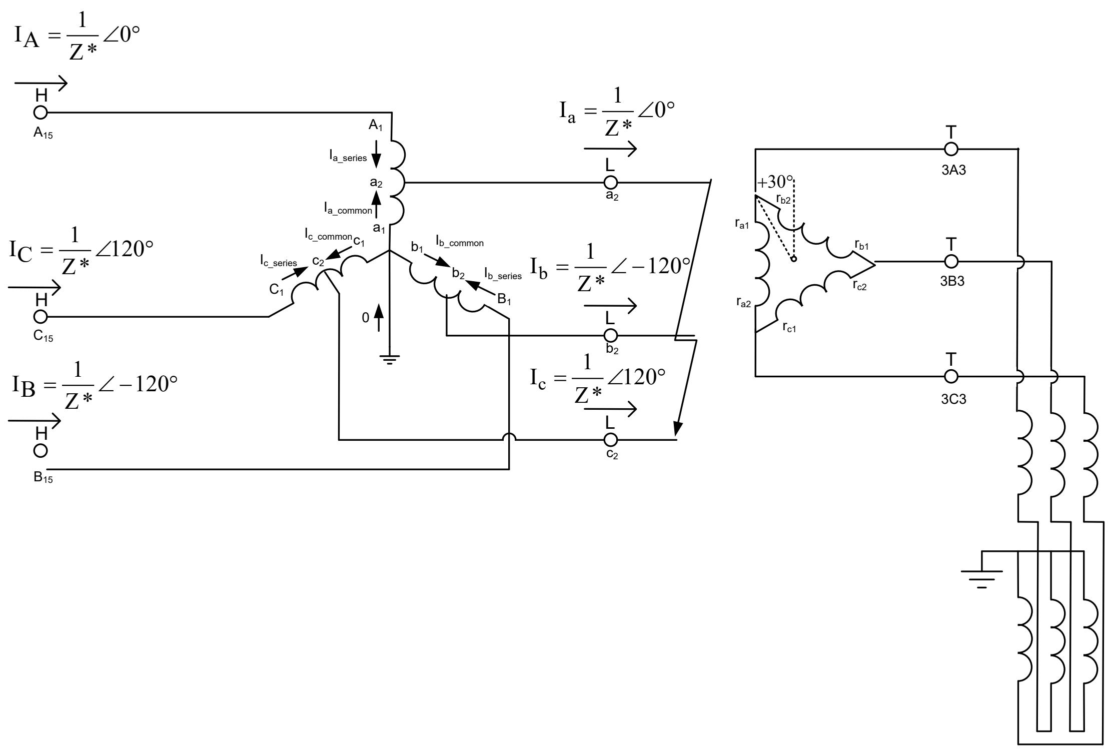
18.3.1.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z*}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{1\angle -120°}{Z*}$$

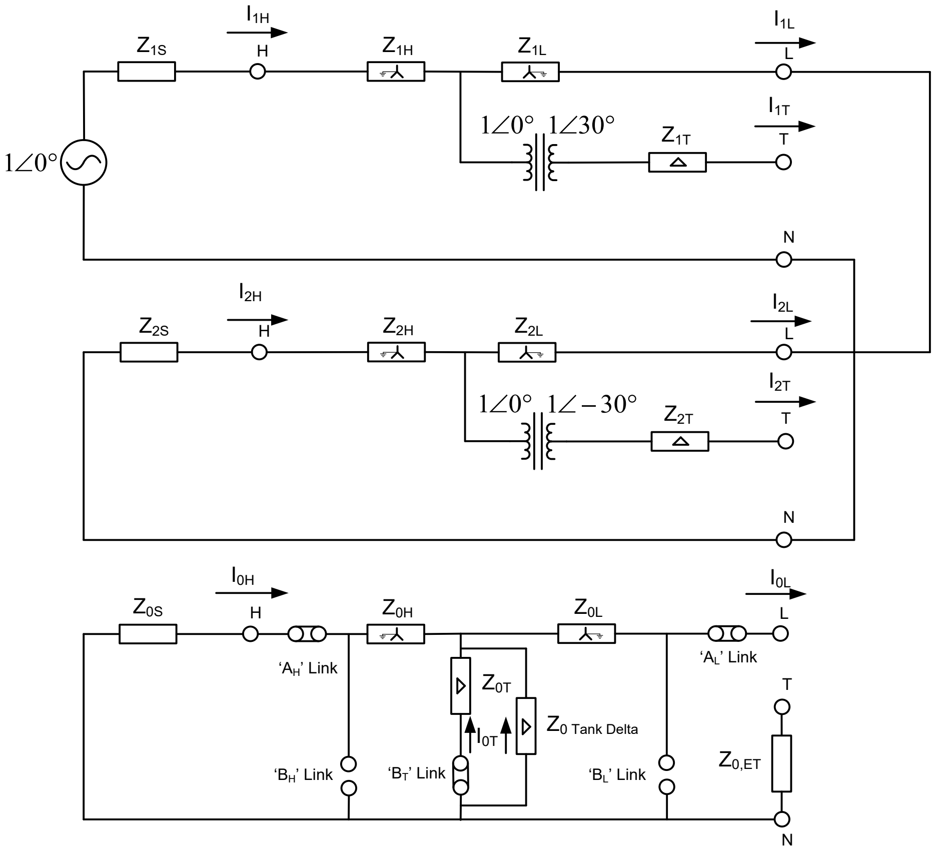
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{1\angle 120°}{Z*}$$

18.3.1.4 Phase Current Diagram



18.3.2 Phase to Phase LV Fault

18.3.2.1 Sequence Network



18.3.2.2 Sequence Currents

Define $Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z^{**}}$ $\qquad$ $I_{1L} = \frac{1\angle 0°}{Z^{**}}$

$I_{2H} = \frac{-1\angle 0°}{Z^{**}}$ $\qquad$ $I_{2L} = \frac{-1\angle 0°}{Z^{**}}$

$I_{0H} = 0$ $\qquad$ $I_{0L} = 0$

$I_{1T} = 0$ $\qquad$ $I_{2T} = 0$ $\qquad$ $I_{0T} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

$I_{2H} = I_{2L}$

$I_{1H} = -I_{2H}$

$I_{1L} = -I_{2L}$

18.3.2.3 Phase Currents

For a ‘b’ to ‘c’ fault

18.3.2.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z^{**}} + \frac{-1\angle 0°}{Z^{**}} = 0$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 120°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle -90°}{Z^{**}}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 240°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle 90°}{Z^{**}}$$

18.3.2.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z^{**}} + \frac{-1\angle 0°}{Z^{**}} = 0$$

$$I_B =_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 120°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle -90°}{Z^{**}}$$

$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 240°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle 90°}{Z^{**}}$$

18.3.2.3.3 Tertiary Currents

$$I_{aT} = I_{0T} + I_{1T} + aI_{2T} = 0$$

$$I_{bT} = I_{0T} + a^2 I_{1T} + aI_{2T} = 0$$

$$I_{cT} = I_{0T} + aI_{1T} + a^2 I_{2T} = 0$$

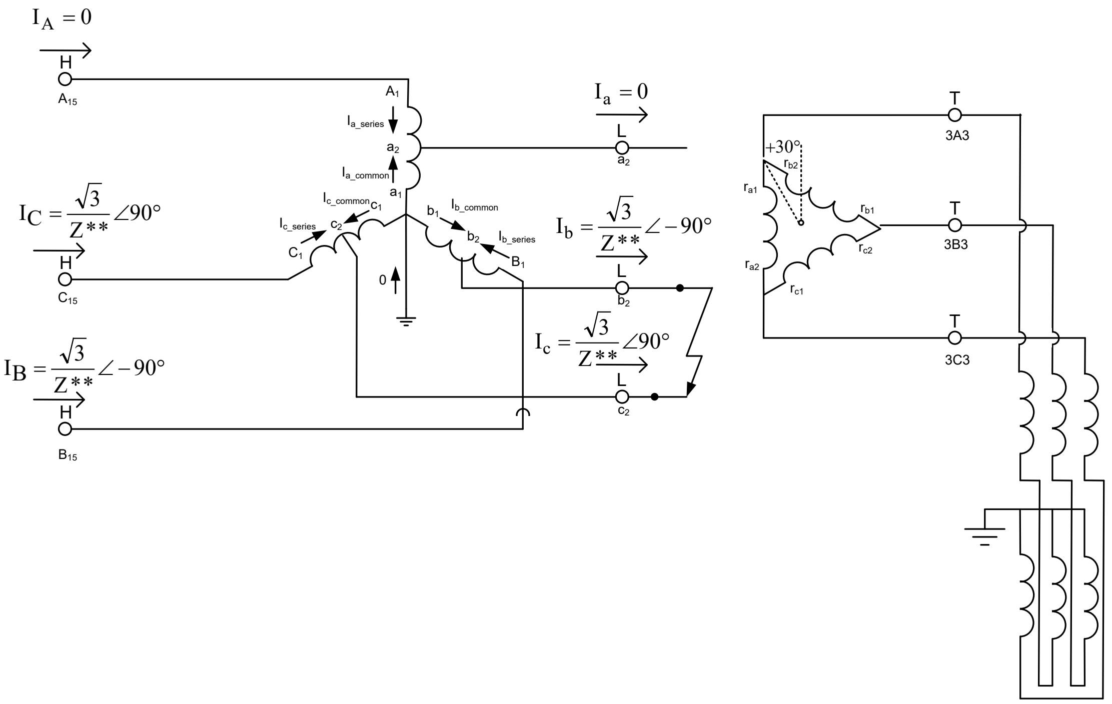
18.3.2.3.4 Common Currents

$$I_{a\_Common} = I_a - I_A = 0$$

$$I_{b\_Common} = I_b - I_B = 0$$

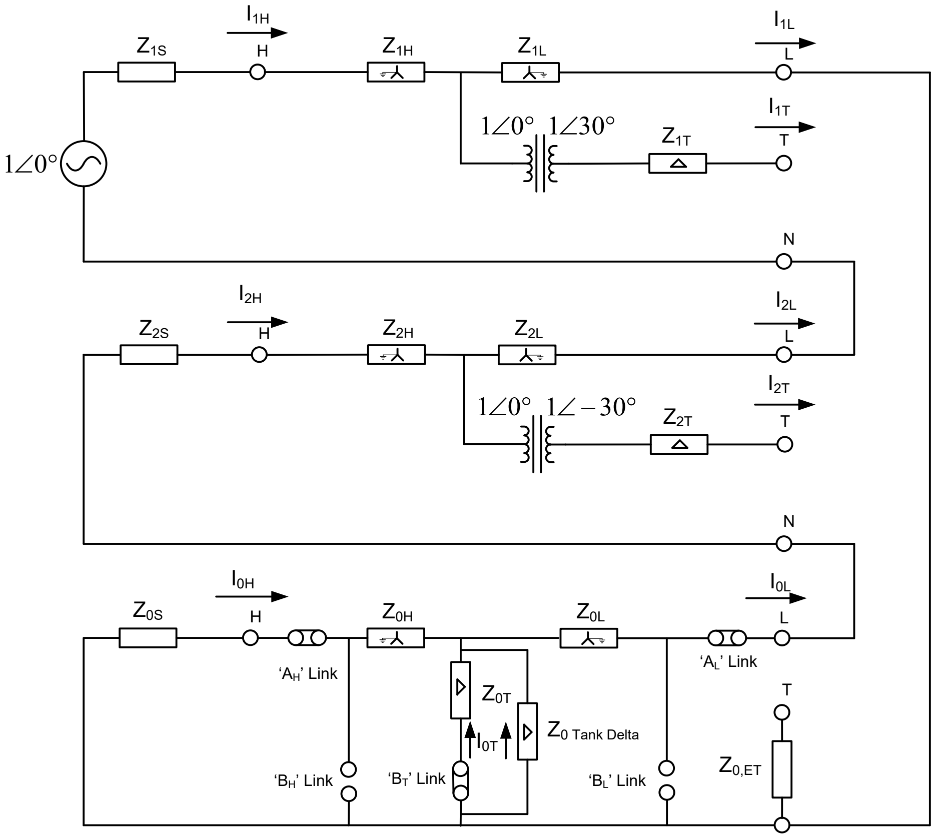
$$I_{c\_Common} = I_c - I_C = 0$$

18.3.2.4 Phase Current Diagram



18.3.3 Phase to Earth LV Fault

18.3.3.1 Sequence Network



18.3.3.2 Sequence Currents

Define$Z^{***} = 2(Z_{1S} + Z_{1H} + Z_{1L}) + Z_{0L} + \frac{Z_{0T}(Z_{0S}+Z_{0H})}{Z_S+Z_{0H}+Z_{0T}}$ This is the impedance used to determine the common current through the:

1) Positive sequence HV and LV Terminals

2) Negative sequence HV and LV Terminals

3) Zero sequence LV Terminals

$\frac{Z_{0T}}{Z_{0S}+Z_{0H}+Z_{0T}}$ is the current divider factor used to determine the portion of the common current that flows through the zero sequence HV Terminals.

$\frac{Z_{0S}+Z_{0H}}{Z_{0S}+Z_{0H}+Z_{0T}}$ is the current divider factor used to determine the portion of the common current that flows through the zero sequence tertiary winding.

The sequence currents can then be written as:

$I_{1H} = \frac{1\angle 0° V}{Z^{***}}$ $\qquad$ $I_{1L} = \frac{1\angle 0° V}{Z^{***}}$

$I_{2H} = \frac{1\angle 0° V}{Z^{***}}$ $\qquad$ $I_{2L} = \frac{1\angle 0° V}{Z^{***}}$

$I_{0H} = \frac{1\angle 0° V\left(\frac{Z_{0T}}{Z_{0S}+Z_{0H}+Z_{0T}}\right)}{Z^{***}}$ $\qquad I_{0L} = \frac{1\angle 0° V}{Z^{***}}$

$I_{1T} = 0$ $\qquad I_{2T} = 0$ $\qquad I_{0T} = \frac{1\angle 0° V\left(\frac{Z_{0S}+Z_{0H}}{Z_{0S}+Z_{0H}+Z_{0T}}\right)}{Z^{***}}$

From the sequence network it can be seen that:

$I_{0L} = I_{1L} = I_{2L} = I_{1H} = I_{2H}$

$I_{0L} = I_{0H} + I_{0T}$

18.3.3.3 Phase Currents

18.3.3.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{3\angle 0°}{Z^{***}}$$

$$I_b = I_{0L} + a^2 I_{1L} + \mathrm{a}I_{2L} = \frac{(1\angle 0°)}{Z^{***}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{***}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{***}} = 0$$

$$I_c = I_{0L} + a^2 I_{1L} + \mathrm{a}I_{2L} = \frac{(1\angle 0°)}{Z^{***}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{***}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{***}} = 0$$

18.3.3.3.2 Line Currents through the HV Terminals

$$I_A = 2I_{1H} + I_{0H} = \frac{2\angle 0° + 1\angle 0° \left(\frac{Z_{0T}}{Z_{0S} + Z_{0H} + Z_{0T}}\right)}{Z\ ***}$$

$$I_A = \frac{1\angle 0° \left(2 + \frac{Z_{0T}}{Z_{0S} + Z_{0H} + Z_{0T}}\right)}{Z\ ***}$$

$$I_B = I_{0H} + a^2 I_{1H} + \mathrm{a}I_{2H} = -I_{0T} = \frac{1\angle 180° \left(\frac{Z_{0S} + Z_{0H}}{Z_{0S} + Z_{0H} + Z_{0T}}\right)}{Z\ ***}$$

$$I_C = I_{0H} + a^2 I_{1H} + \mathrm{a}I_{2H} = -I_{0T} = \frac{1\angle 180° \left(\frac{Z_{0S} + Z_{0H}}{Z_{0S} + Z_{0H} + Z_{0T}}\right)}{Z\ ***}$$

18.3.3.3.3 Current through HV Neutral

The current in the HV neutral is the sum of the common currents induced by the delta windings ($3I_{0T}$):

$$I_{\text{neutral}} = \frac{3I_{0T}}{Z\ ***} = \frac{3}{Z***}\left(\frac{Z_{0S} + Z_{0H}}{Z_{0S} + Z_{0H} + Z_{0T}}\right)\angle 0°$$

18.3.3.3.4 Tertiary Currents

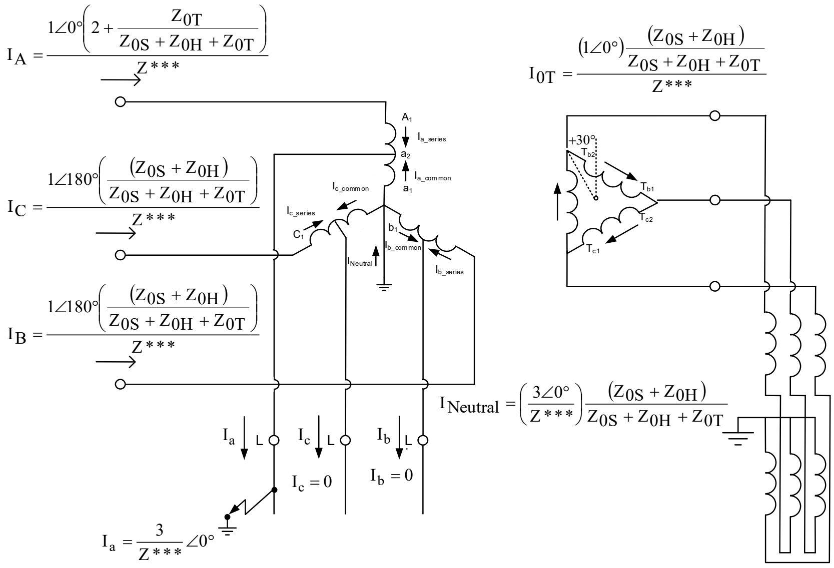
The current in the delta tertiary is given by

$$I_{0T} = \frac{1\angle 0°\left(\frac{Z_{0S} + Z_{0H}}{Z_{0S} + Z_{0H} + Z_{0T}}\right)}{Z***}$$

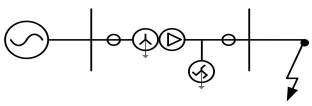
18.3.3.3.5 Common Currents

For autotransformers current in HV is combined directly with currents in LV (e.g HV currents should be subtracted from the LV currents to obtain common winding currents in an autotransformer.) This calculation is to be performed in real amperes after HV and LV currents are established and cannot be done in per unit quantities without a convenient base.

18.3.3.4 Phase Current Diagram

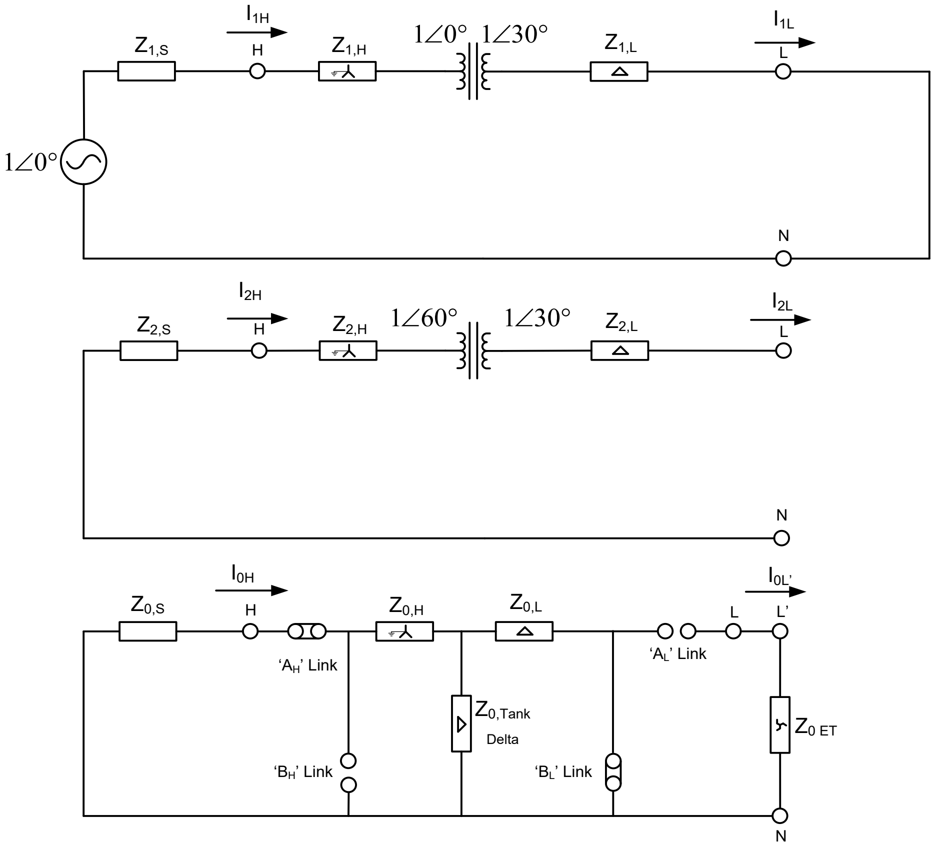


18.4 Star-Delta with LV Earthing Transformer (Ynd11 + zn)



18.4.1 Three Phase LV Fault

18.4.1.1 Sequence Network



18.4.1.2 Sequence Currents

Define $Z^* = Z_{1S} + Z_{1H} + Z_{1L}$

$I_{1H} = \frac{1\angle 0°}{Z^*}$ $\qquad$ $I_{1L} = \frac{1\angle 30°}{Z^*}$

$I_{2H} = 0$ $\qquad$ $I_{2L} = 0$

$I_{0H} = 0$ $\qquad$ $I_{0L} = 0$ $\qquad$ $I_{0L'} = 0$

18.4.1.3 Phase Currents

18.4.1.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 30°}{Z*}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 30°)}{Z*} = \frac{1\angle -90°}{Z*}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 30°)}{Z*} = \frac{1\angle 150°}{Z*}$$

18.4.1.3.2 Phase Currents in the Delta Winding

$$I_{a\_phase} = \frac{1\angle 0°}{\sqrt{3}Z*}$$

$$I_{b\_phase} = \frac{1\angle -120°}{\sqrt{3}Z*}$$

$$I_{c\_phase} = \frac{1\angle 120°}{\sqrt{3}\,Z*}$$

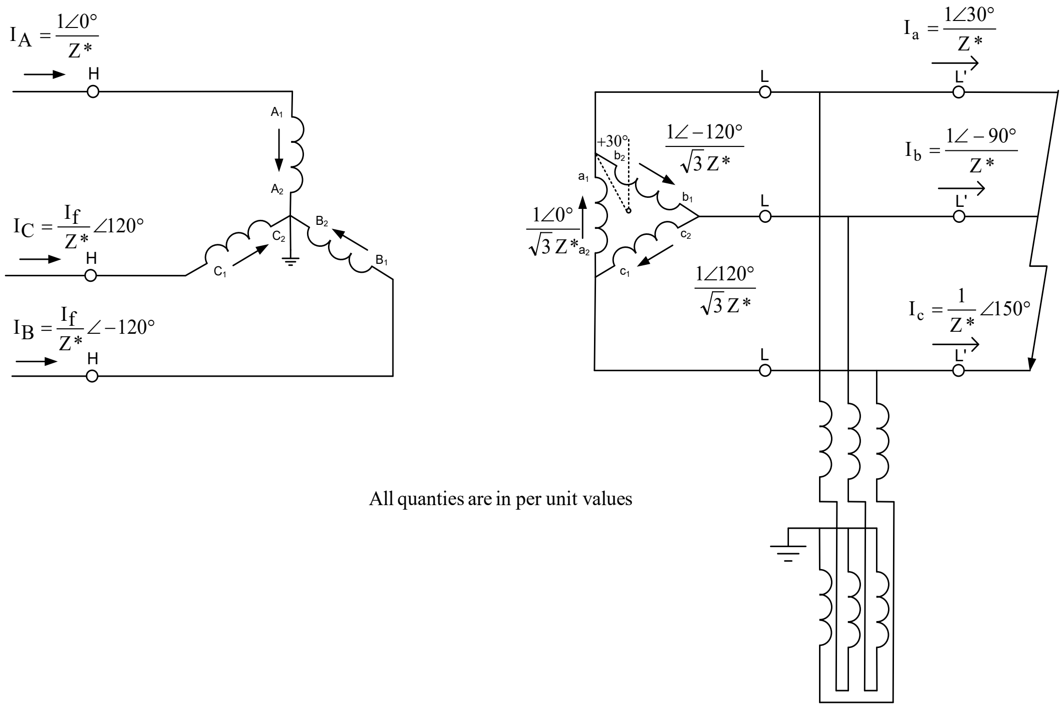
18.4.1.3.3 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z*}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{(1\angle -120°)}{Z*}$$

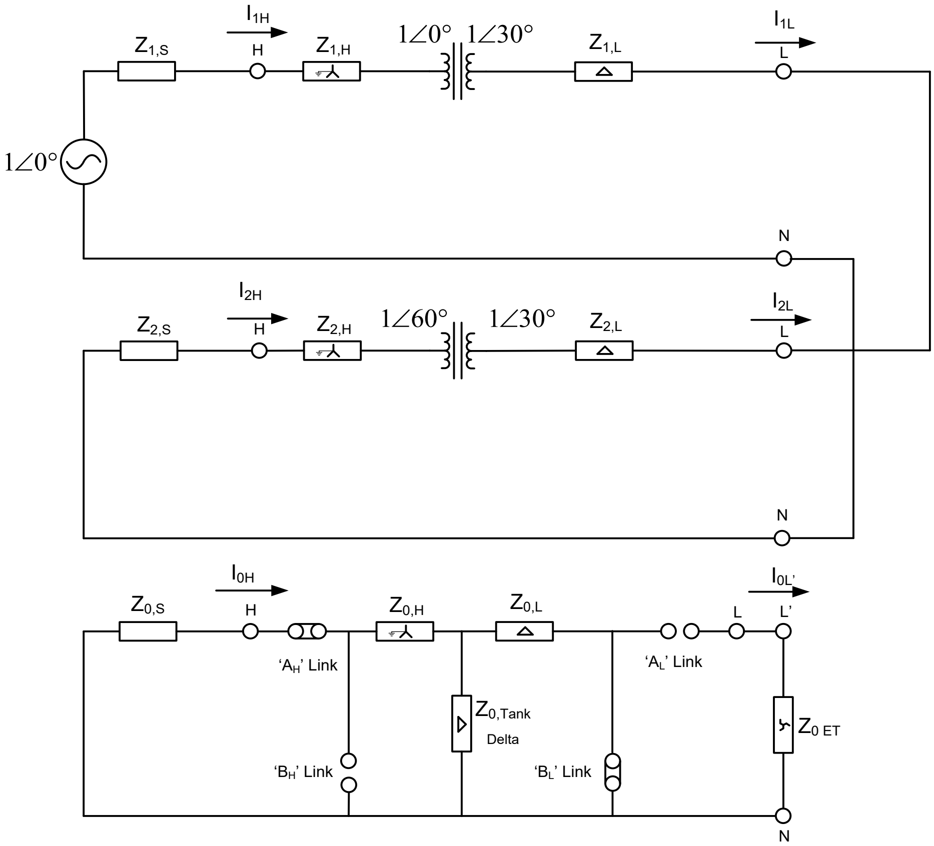
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{1\angle 120°}{Z*}$$

18.4.1.4 Phase Current Diagram



18.4.2 Phase to Phase LV Fault

18.4.2.1 Sequence Network



18.4.2.2 Sequence Currents

Define Z** $= Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z^{**}}$ $\qquad$ $I_{1L} = \frac{1\angle 30°}{Z^{**}}$

$I_{2H} = \frac{-1\angle 60°}{Z^{**}}$ $\qquad$ $I_{2L} = \frac{-1\angle 30°}{Z^{**}}$

$I_{0H} = 0$ $\qquad$ $I_{0L} = 0$ $\qquad$ $I_{0L'} = 0$

From the sequence network it can be seen that:

$I_{1L} = I_{2L}$

18.4.2.3 Phase Currents

18.4.2.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 30°}{Z^{**}} + \frac{-1\angle 30°}{Z^{**}} = 0$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 30°)}{Z^{**}} + \frac{(1\angle 120°)(-1\angle 30°)}{Z^{**}} = \frac{\sqrt{3}\angle -60°}{Z^{**}}$$

$$I_c = I_{0L} + aI_{1L} - a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 30°)}{Z^{**}} + \frac{(1\angle 240°)(-1\angle 30°)}{Z^{**}} = \frac{\sqrt{3}\angle 120°}{Z^{**}}$$

18.4.2.3.2 Phase Currents in the Delta Winding

If the impedances of the three delta windings are equal, then the fault current will be divided with 2/3 going through the 'c' phase winding and 1/3 going through the 'a' and 'b' phase windings. These two currents will sum at the 'b' phase LV Terminals.

$$I_{\text{a\_phase}} = \frac{I_b}{3} = \frac{1\angle -60°}{\sqrt{3}Z^{**}}$$

$$I_{\text{b\_phase}} = \frac{I_b}{3} = \frac{1\angle -60°}{\sqrt{3}Z^{**}}$$

$$I_{\text{c\_phase}} = \frac{2I_b}{3} = \frac{2\angle -60°}{\sqrt{3}Z^{**}}$$

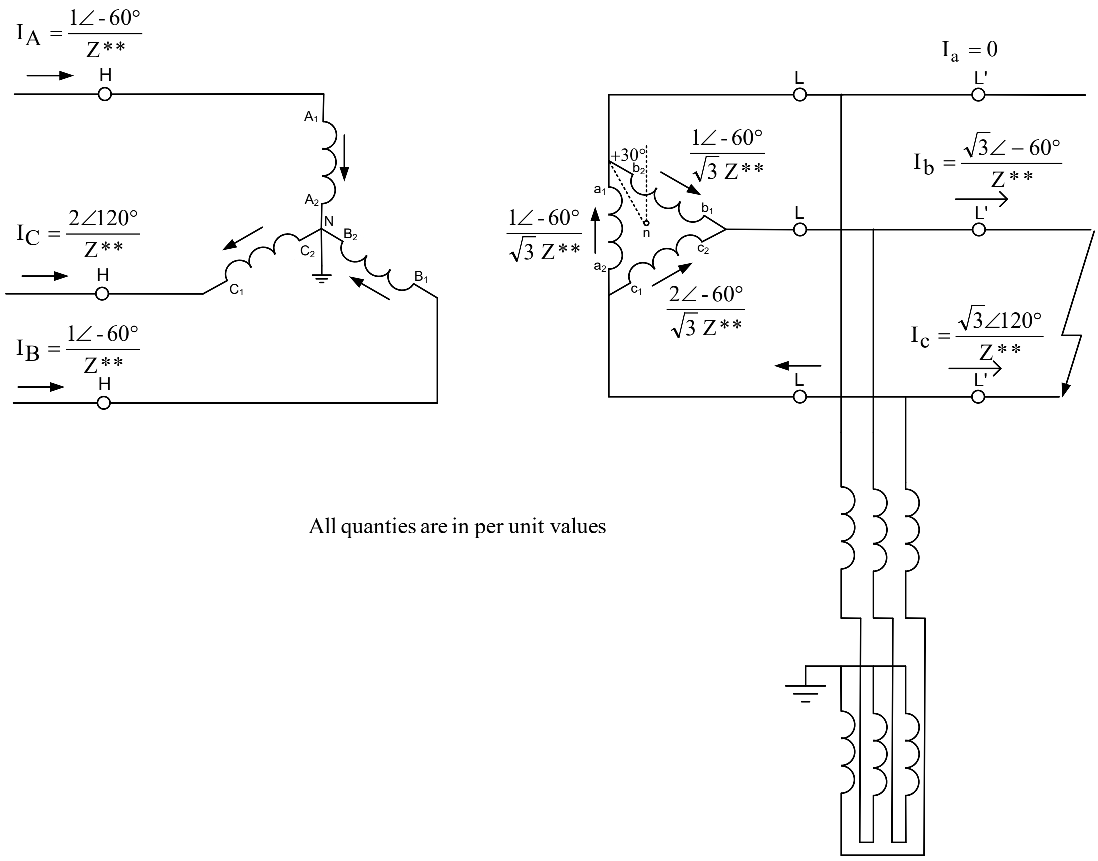
18.4.2.3.3 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z^{**}} + \frac{-1\angle 60°}{Z^{**}} = \frac{1\angle -60°}{Z^{**}}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 120°)(-1\angle 60°)}{Z^{**}} = \frac{1\angle -60°}{Z^{**}}$$

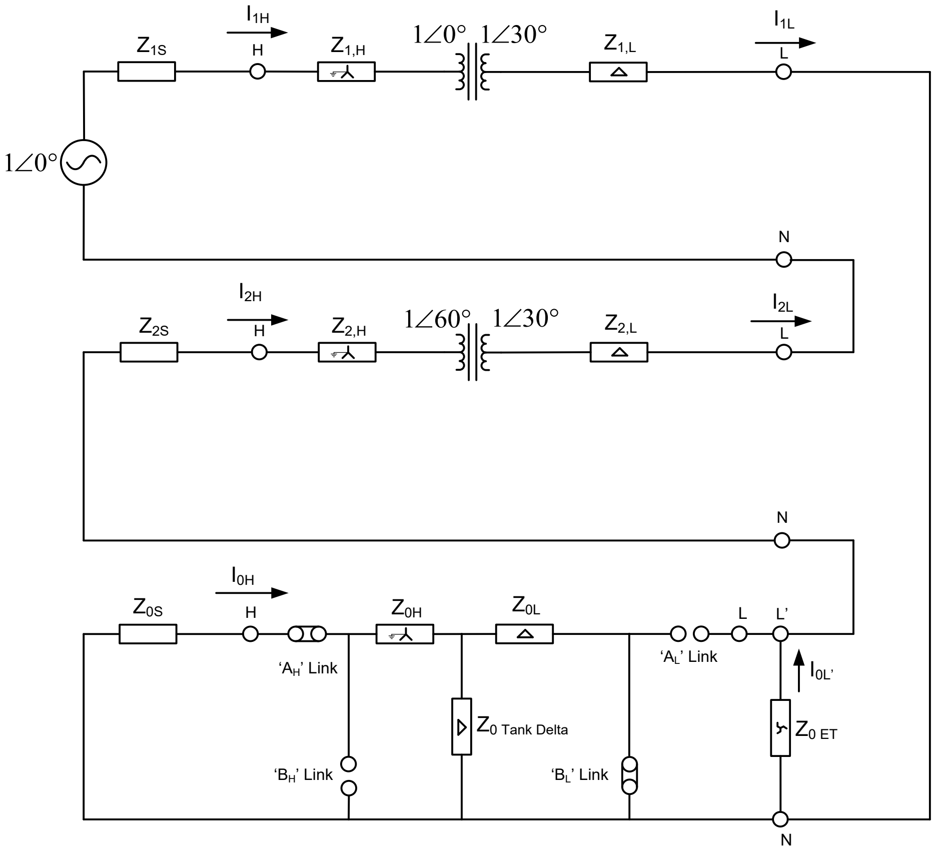
$$I_C = I_{0H} + aI_{1H} - a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 240°)(-1\angle 60°)}{Z^{**}} = \frac{2\angle 120°}{Z^{**}}$$

18.4.2.4 Phase Current Diagram



18.4.3 Phase to Earth LV Fault

18.4.3.1 Sequence Network



18.4.3.2 Sequence Currents

Define $Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$$I_{1H} = \frac{1\angle 0°}{Z^{**} + Z_{0\ ET}} \qquad I_{1L} = \frac{1\angle 30°}{Z^{**} + Z_{0\ ET}}$$

$$I_{2H} = \frac{1\angle 60°}{Z^{**} + Z_{0\ ET}} \qquad I_{2L} = \frac{1\angle 30°}{Z^{**} + Z_{0\ ET}}$$

$$I_{0H} = 0 \qquad I_{0L} = 0 \qquad I_{0L'} = \frac{1\angle 0°}{Z^{**} + Z_{0\ ET}}$$

From the sequence network it can be seen that:

$$I_{0L'} = I_{1H} = I_{2L}$$

18.4.3.3 Phase Currents

18.4.3.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 30°}{Z^{**} + Z_{0\,ET}} + \frac{1\angle 30°}{Z^{**} + Z_{0\,ET}} = 2\angle 30°$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 30°)}{Z^{**} + Z_{0\,ET}} + \frac{(1\angle 120°)(1\angle 30°)}{Z^{**} + Z_{0\,ET}} = \frac{(1\angle -150°)}{Z^{**} + Z_{0\,ET}}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 30°)}{Z^{**} + Z_{0\,ET}} + \frac{(1\angle 240°)(1\angle 30°)}{Z^{**} + Z_{0\,ET}} = \frac{(1\angle -150°)}{Z^{**} + Z_{0\,ET}}$$

18.4.3.3.2 Phase Currents in the Delta Winding

In steady state conditions the ‘a’ and ‘b’ phase winding will each carry currents equivalent to I_0.

$$I_{a\_phase} = \frac{1\angle 30°}{Z^{**} + Z_{0ET}}$$

$$I_{b\_phase} = \frac{1\angle 30°}{Z^{**} + Z_{0ET}}$$

$$I_{c\_phase} = 0$$

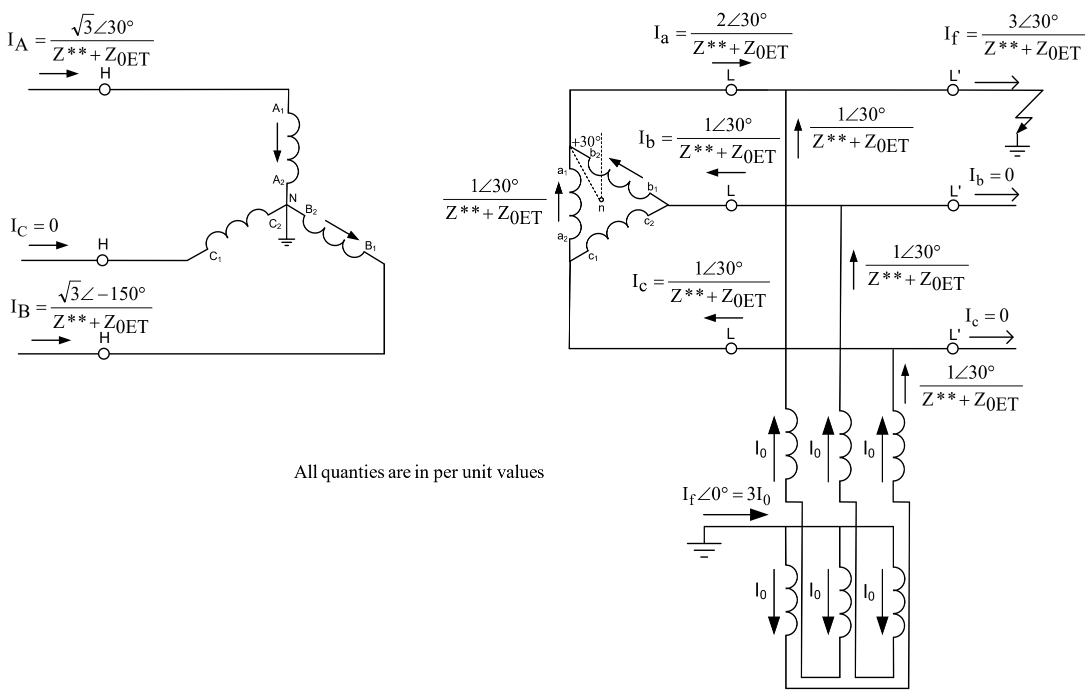
18.4.3.3.3 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{(Z^{**} + Z_{0\,ET})} + \frac{1\angle 60°}{(Z^{**} + Z_{0\,ET})} = \frac{\sqrt{3}\angle 30°}{(Z^{**} + Z_{0\,ET})}$$

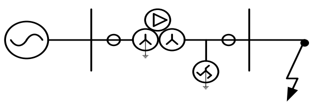
$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{(Z^{**} + Z_{0\,ET})} + \frac{(1\angle 120°)(1\angle 60°)}{(Z^{**} + Z_{0\,ET})} = \frac{\sqrt{3}\angle -150°}{(Z^{**} + Z_{0\,ET})}$$

$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{(Z^{**} + Z_{0\,ET})} + \frac{(1\angle 240°)(1\angle 60°)}{(Z^{**} + Z_{0\,ET})} = 0$$

18.4.3.4 Phase Current Diagram

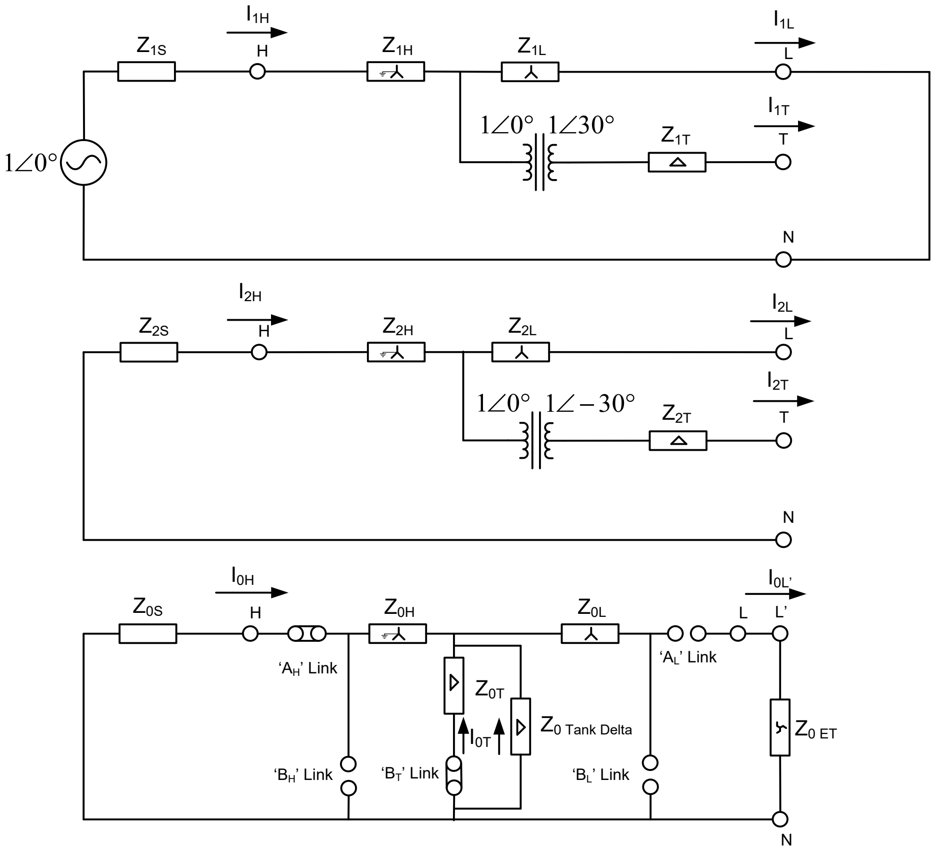


18.5 Star-Delta-Star, HV Earthed, LV Earthing Transformer (Ynd11y + zn)



18.5.1 Three Phase LV Fault

18.5.1.1 Sequence Network



18.5.1.2 Sequence Currents

Define$Z^* = Z_{1S} + Z_{1H} + Z_{1L}$

$I_{1H} = \frac{1\angle 0°}{Z^*}$ $I_{1L} = \frac{1\angle 0°}{Z^*}$

$I_{2H} = 0$ $I_{2L} = 0$

$I_{0H} = 0$ $I_{0L} = 0$ $I_{0L'} = 0$

$I_{1T} = 0$ $I_{2T} = 0$ $I_{0T} = 0$

From the sequence network it can be seen that $I_{1H} = I_{1L}$

18.5.1.3 Phase Currents

18.5.1.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z*}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{(1\angle -120°)}{Z*}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{(1\angle 120°)}{Z*}$$

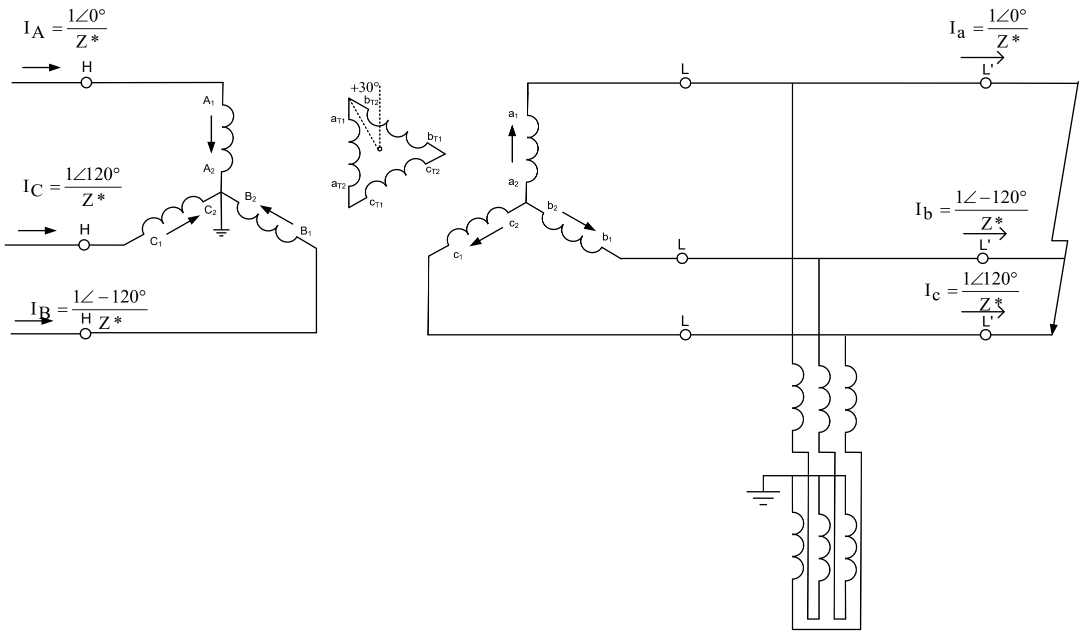
18.5.1.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z*}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{(1\angle -120°)}{Z*}$$

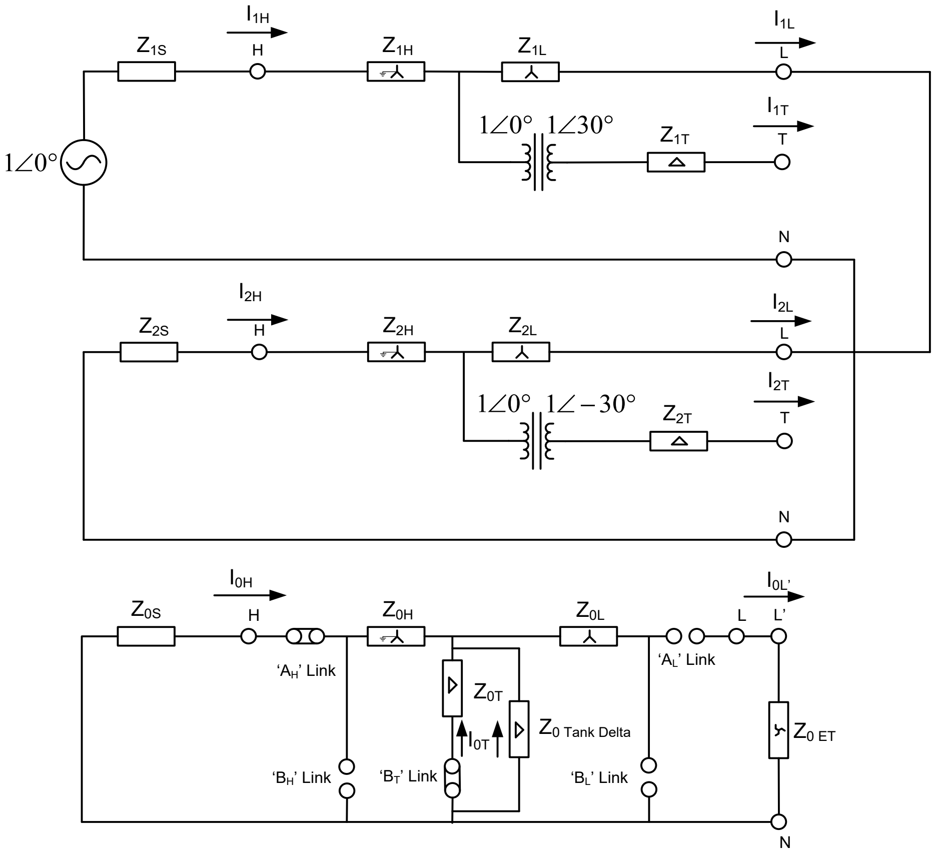
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{(1\angle 120°)}{Z*}$$

18.5.1.4 Phase Current Diagram



18.5.2 Phase to Phase LV Fault

18.5.2.1 Sequence Network



18.5.2.2 Sequence Currents

Define $Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z^{**}}$ $I_{1L} = \frac{1\angle 0°}{Z^{**}}$

$I_{2H} = \frac{-1\angle 0°}{Z^{**}}$ $I_{2L} = \frac{-1\angle 0°}{Z^{**}}$

$I_{0H} = 0$ $I_{0L} = 0$ $I_{0L'} = 0$

$I_{1T} = 0$ $I_{2T} = 0$ $I_{0T} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

$I_{2H} = I_{2L}$

$I_{1H} = I_{2H}$

$I_{1L} = I_{2L}$

18.5.2.3 Phase Currents

18.5.2.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z**} + \frac{-1\angle 0°}{Z**} = 0$$

$$I_b = I_{0L} + a^2 I_{1L} + \mathrm{aI}_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z**} + \frac{(1\angle 120°)(-1\angle 0°)}{Z**} = \frac{\sqrt{3}\angle -90°}{Z**}$$

$$I_c = I_{0L} + \mathrm{aI}_{1L} - a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z\ **} + \frac{(1\angle 240°)(-1\angle 0°)}{Z\ **} = \frac{\sqrt{3}\angle 90°}{Z**}$$

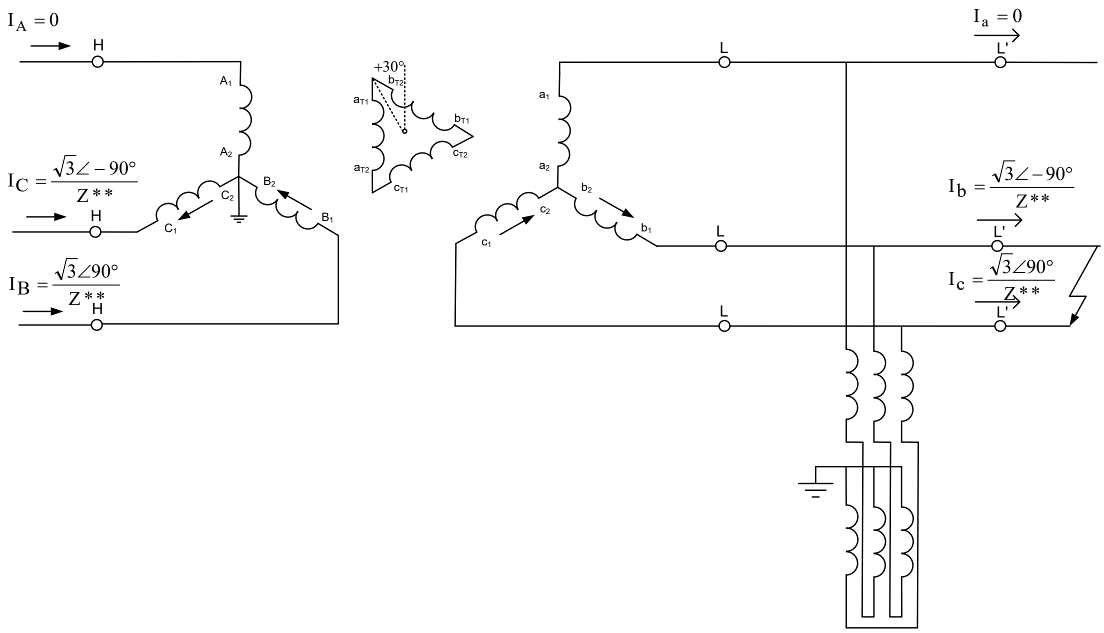
18.5.2.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z**} + \frac{-1\angle 0°}{Z**} = 0$$

$$I_B = I_{0H} + a^2 I_{1H} + \mathrm{aI}_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z**} + \frac{(1\angle 120°)(-1\angle 0°)}{Z**} = \frac{\sqrt{3}\angle -90°}{Z**}$$

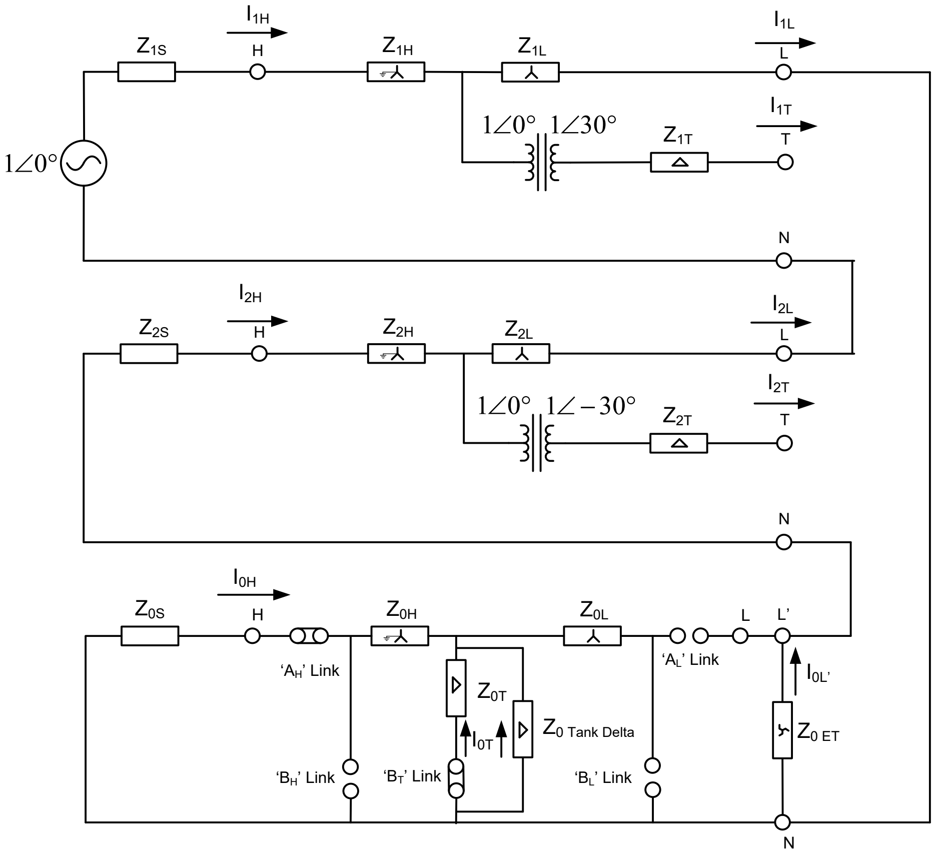
$$I_C = I_{0H} + \mathrm{aI}_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z**} + \frac{(1\angle 240°)(-1\angle 0°)}{Z**} = \frac{\sqrt{3}\angle 90°}{Z**}$$

18.5.2.4 Phase Current Diagram



18.5.3 Phase to Earth LV Fault

18.5.3.1 Sequence Network



18.5.3.2 Sequence Currents

Define $Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z^{**} + Z_{0\ ET}}$ $\quad I_{1L} = \frac{1\angle 0°}{Z^{**} + Z_{0\ ET}}$

$I_{2H} = \frac{1\angle 0°}{Z^{**} + Z_{0\ ET}}$ $\quad I_{2L} = \frac{1\angle 0°}{Z^{**} + Z_{0\ ET}}$

$I_{0H} = 0$ $\quad I_{0L} = 0$ $\quad I_{0L'} = \frac{1\angle 0°}{Z^{**} + Z_{0\ ET}}$

$I_{1T} = 0$ $\quad I_{2T} = 0$ $\quad I_{0T} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L} = I_{2H} = I_{2L} = I_{0L'}$

18.5.3.3 Phase Currents

18.5.3.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z** + Z_{0\,ET}} + \frac{1\angle 0°}{Z** + Z_{0\,ET}} = \frac{2\angle 0°}{Z** + Z_{0\,ET}}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z** + Z_{0\,ET}} + \frac{(1\angle 120°)(1\angle 0°)}{Z** + Z_{0\,ET}} = \frac{1\angle 180°}{Z** + Z_{0\,ET}}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z** + Z_{0\,ET}} + \frac{(1\angle 240°)(1\angle 0°)}{Z** + Z_{0\,ET}} = \frac{1\angle 180°}{Z** + Z_{0\,ET}}$$

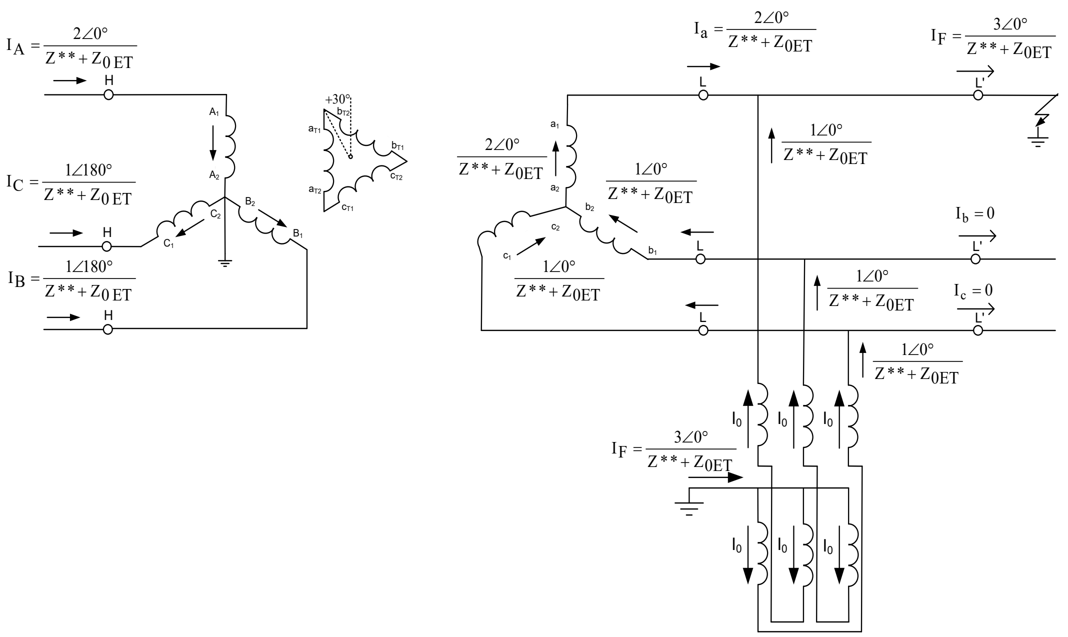
18.5.3.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = 0 + \frac{1\angle 0°}{Z** + Z_{0\,ET}} + \frac{1\angle 0°}{Z** + Z_{0\,ET}} = \frac{2\angle 0°}{Z** + Z_{0\,ET}}$$

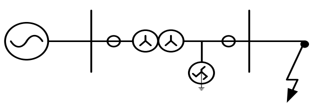
$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z** + Z_{0\,ET}} + \frac{(1\angle 120°)(1\angle 0°)}{Z** + Z_{0\,ET}} = \frac{1\angle 180°}{Z** + Z_{0\,ET}}$$

$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z** + Z_{0\,ET}} + \frac{(1\angle 240°)(1\angle 0°)}{Z** + Z_{0\,ET}} = \frac{1\angle 180°}{Z** + Z_{0\,ET}}$$

18.5.3.4 Phase Current Diagram

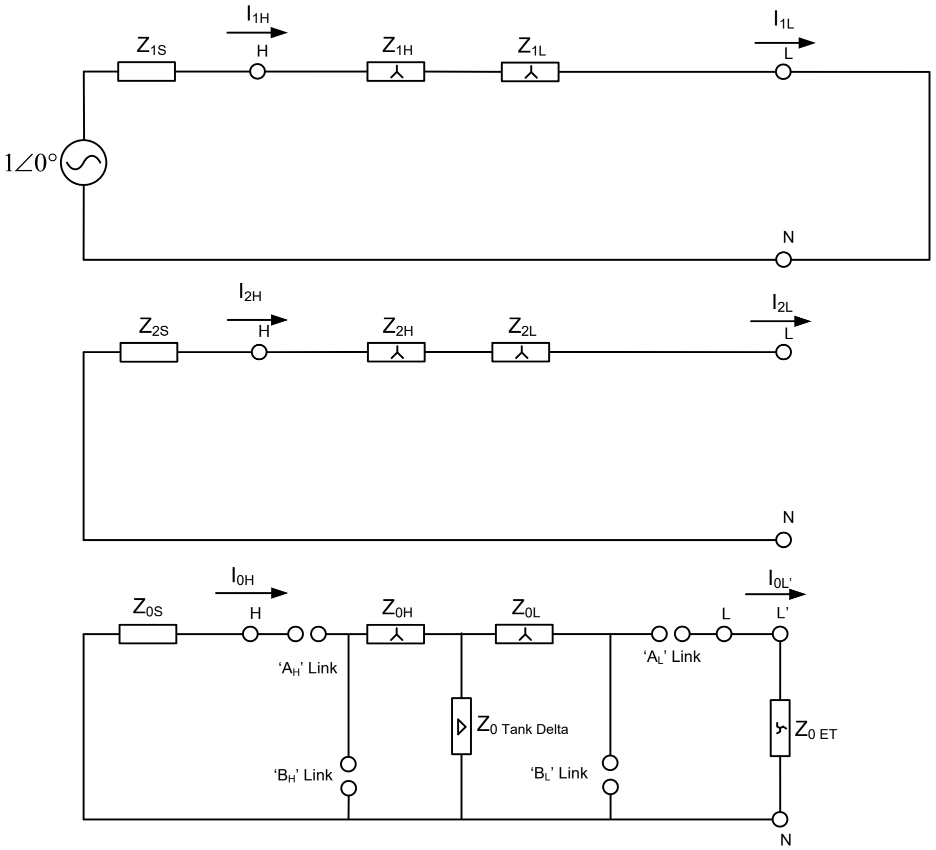


18.6 Star-Star, LV Earthing Transformer (Yy+zn)



18.6.1 Three Phase LV Fault

18.6.1.1 Sequence Network



18.6.1.2 Sequence Currents

Define $Z^* = Z_{1S} + Z_{1H} + Z_{1L}$

$I_{1H} = \frac{1\angle 0°}{Z^*}$ $\qquad$ $I_{1L} = \frac{1\angle 0°}{Z^*}$

$I_{2H} = 0$ $\qquad$ $I_{2L} = 0$

$I_{0H} = 0$ $\qquad$ $I_{0L} = 0$ $\qquad$ $I_{0L'} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

18.6.1.3 Phase Currents

18.6.1.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z*}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{1\angle -120°}{Z*}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{(1\angle 120°)}{Z*}$$

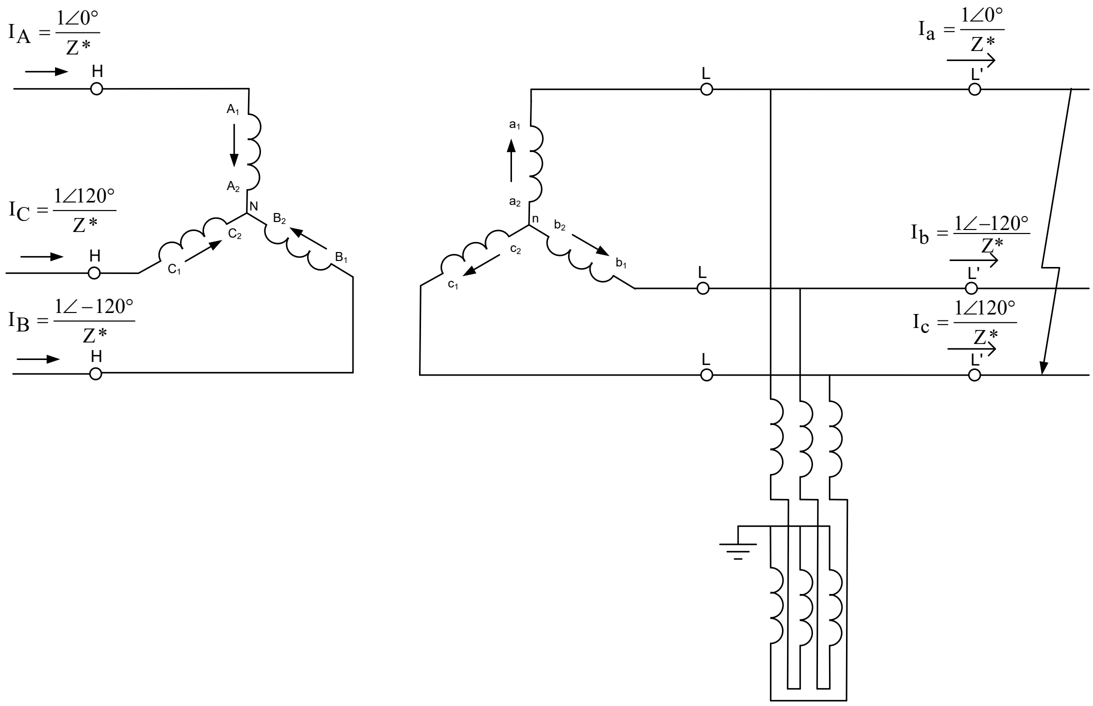
18.6.1.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z*}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{1\angle -120°}{Z*}$$

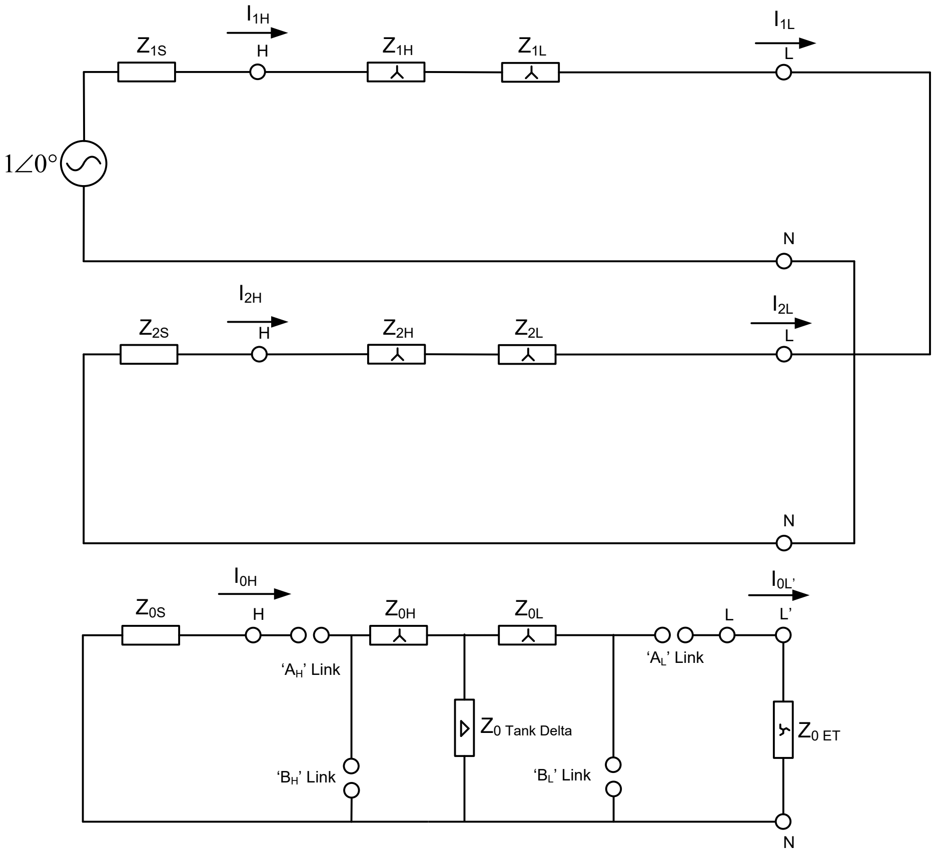
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{(1\angle 120°)}{Z*}$$

18.6.1.4 Phase Current Diagram



18.6.2 Phase to Phase LV Fault

18.6.2.1 Sequence Network



18.6.2.2 Sequence Currents

Define Z* $*= Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z**}$ $I_{1L} = \frac{1\angle 0°}{Z**}$

$I_{2H} = \frac{-1\angle 0°}{Z**}$ $I_{2L} = \frac{-1\angle 0°}{Z**}$

$I_{0H} = 0$ $I_{0L} = 0$ $I'_{0L} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

$I_{2H} = I_{2L}$

$I_{1H} = I_{2H}$

$I_{1L} = I_{2L}$

18.6.2.3 Phase Currents

18.6.2.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z**} + \frac{-1\angle 0°}{Z**} = 0$$

$$I_b = I_{0L} + a^2 I_{1L} - aI_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z**} + \frac{(1\angle 120°)(-1\angle 0°)}{Z**} \frac{\sqrt{3}\angle -90°}{Z**}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z**} + \frac{(1\angle 240°)(-1\angle 0°)}{Z**} = \frac{\sqrt{3}\angle 90°}{Z**}$$

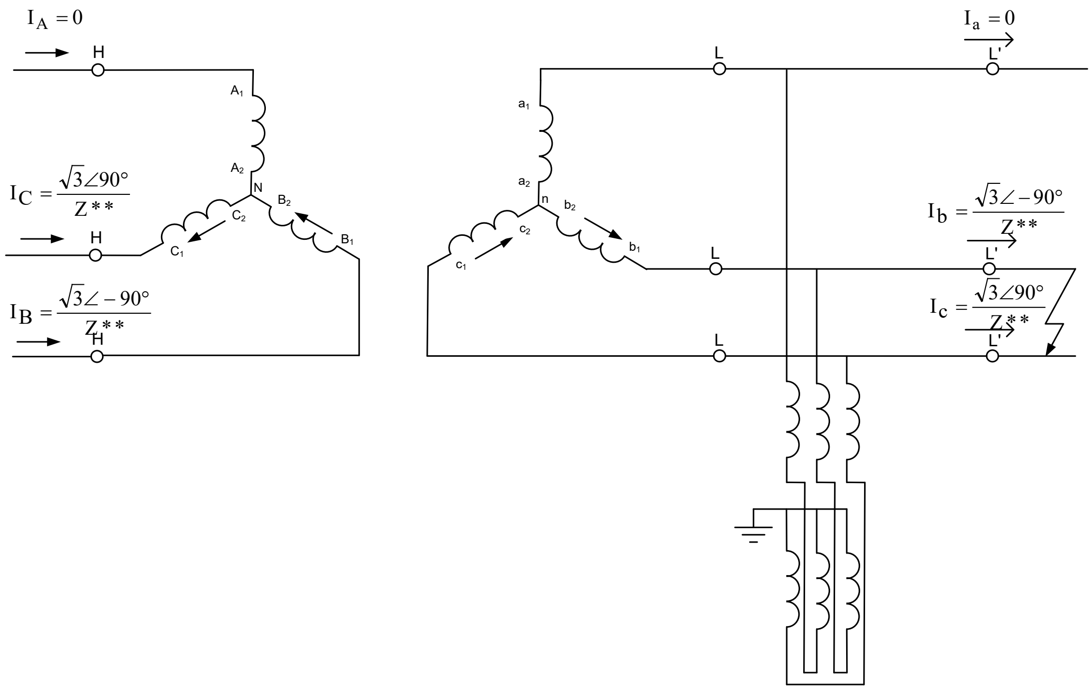
18.6.2.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z**} + \frac{-1\angle 0°}{Z**} = 0$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z**} + \frac{(1\angle 120°)(-1\angle 0°)}{Z**} = \frac{\sqrt{3}\angle -90°}{Z**}$$

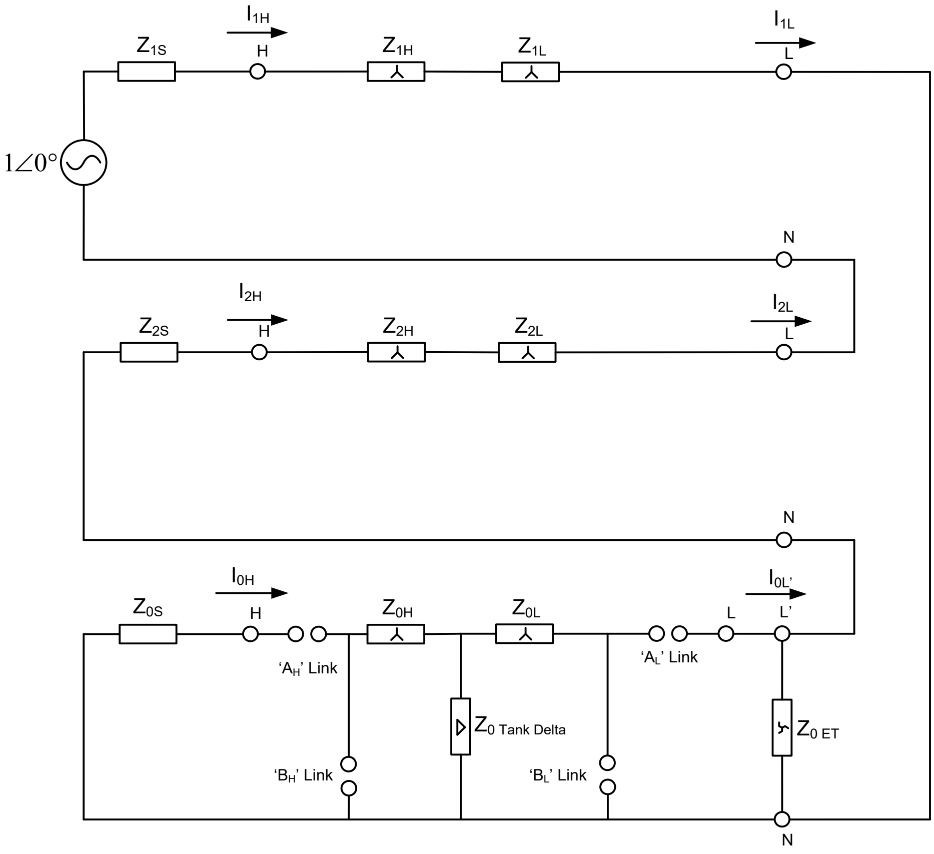
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z**} + \frac{(1\angle 240°)(-1\angle 0°)}{Z**} = \frac{\sqrt{3}\angle 90°}{Z**}$$

18.6.2.4 Phase Current Diagram



18.6.3 Phase to Earth LV Fault

18.6.3.1 Sequence Network



18.6.3.2 Sequence Currents

Define $Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z^{**}+Z_{0\ ET}}$ $\qquad I_{1L} = \frac{1\angle 0°}{Z^{**}+Z_{0\ ET}}$

$I_{2H} = \frac{1\angle 0°}{Z^{**}+Z_{0\ ET}}$ $\qquad I_{2L} = \frac{1\angle 0°}{Z^{**}+Z_{0\ ET}}$

$I_{0H} = 0$ $\qquad I_{0L} = 0$ $\qquad I_{0L'} = \frac{1\angle 0°}{Z^{**}+Z_{0\ ET}}$

From the sequence network it can be seen that:

$I_{1H} = I_{1L} = I_{2H} = I_{2L}$

$I_{0L'} = I_{1L} = I_{2L}$

18.6.3.3 Phase Currents

18.6.3.3.1 Line Currents through the LV Terminals

$$I_a = I_{1\mathrm{L}} + I_{2\mathrm{L}} + I_{0\mathrm{L}} = \frac{2\angle 0°}{Z^{**} + Z_{0\,\mathrm{ET}}}$$

$$I_b = I_{0\mathrm{L}} + a^2 I_{1\mathrm{L}} + \mathrm{aI}_{2\mathrm{L}} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0\,\mathrm{ET}}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0\,\mathrm{ET}}} = \frac{1\angle 180°}{Z^{**} + Z_{0\,\mathrm{ET}}}$$

$$I_c = I_{0\mathrm{L}} + \mathrm{aI}_{1\mathrm{L}} + a^2 I_{2\mathrm{L}} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0\,\mathrm{ET}}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0\,\mathrm{ET}}} = \frac{1\angle 180°}{Z^{**} + Z_{0\,\mathrm{ET}}}$$

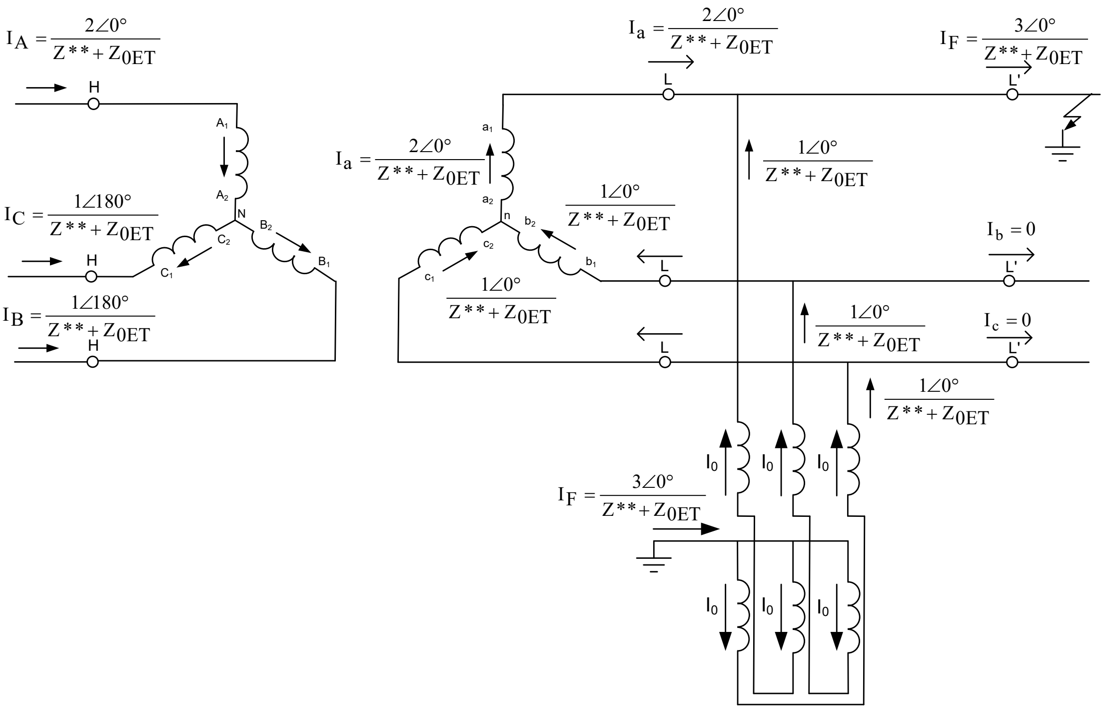
18.6.3.3.2 Line Currents through the HV Terminals

$$I_A = I_{0\mathrm{H}} + I_{1\mathrm{H}} + I_{2\mathrm{H}} = \frac{1\angle 0°}{Z^{**} + Z_{0\,\mathrm{ET}}} + \frac{1\angle 0°}{Z^{**} + Z_{0\,\mathrm{ET}}} = \frac{2\angle 0°}{Z^{**} + Z_{0\,\mathrm{ET}}}$$

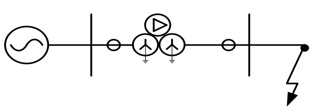
$$I_B = I_{0\mathrm{H}} + a^2 I_{1\mathrm{H}} + \mathrm{aI}_{2\mathrm{H}} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0\,\mathrm{ET}}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0\,\mathrm{ET}}} = \frac{1\angle 180°}{Z^{**} + Z_{0\,\mathrm{ET}}}$$

$$I_C = I_{0\mathrm{H}} + \mathrm{aI}_{1\mathrm{H}} + a^2 I_{2\mathrm{H}} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0\,\mathrm{ET}}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0\,\mathrm{ET}}} = \frac{1\angle 180°}{Z^{**} + Z_{0\,\mathrm{ET}}}$$

18.6.3.4 Phase Current Diagram

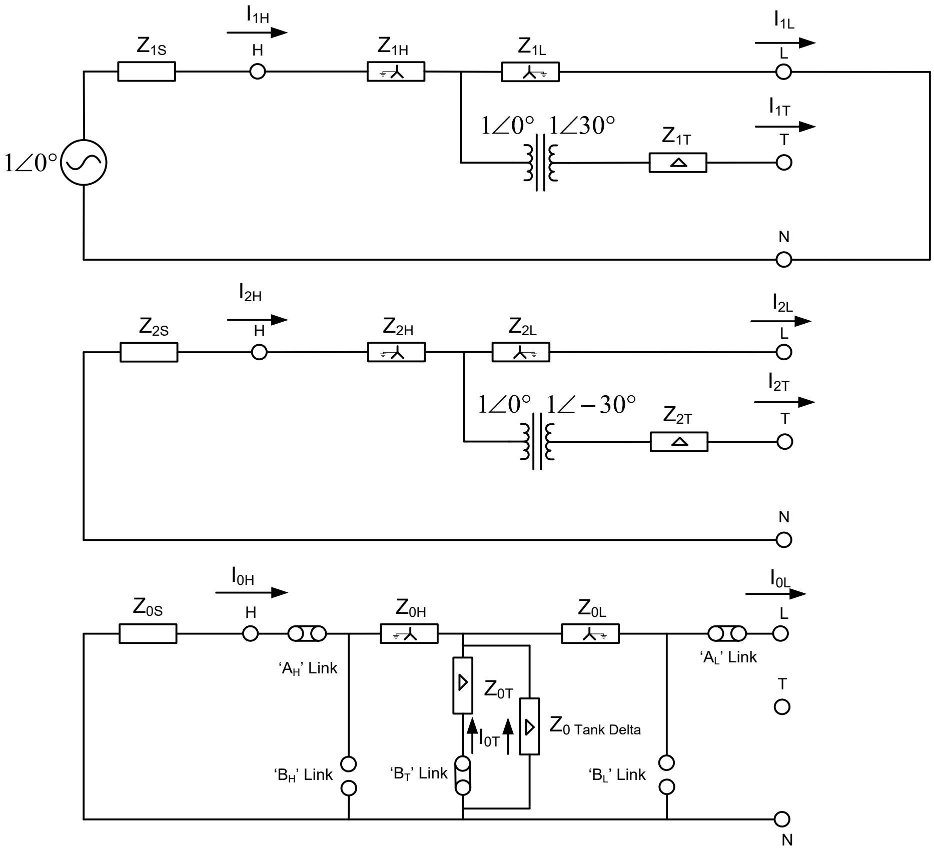


18.7 Star-Delta-Star, HV / LV Solidly Earthed (Ynyn0)



18.7.1 Three Phase LV Fault

18.7.1.1 Sequence Network



18.7.1.2 Sequence Currents

Define $Z^* = Z_{1S} + Z_{1H} + Z_{1L}$

$I_{1H} = \frac{1\angle 0°}{Z^*}$ $\qquad$ $I_{1L} = \frac{1\angle 0°}{Z^*}$

$I_{2H} = 0$ $\qquad$ $I_{2L} = 0$

$I_{0H} = 0$ $\qquad$ $I_{0L} = 0$

$I_{1T} = 0$ $\qquad$ $I_{2T} = 0$ $\qquad$ $I_{0T} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

18.7.1.3 Phase Currents

18.7.1.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z*}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{1\angle -120°}{Z*}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z*}$$

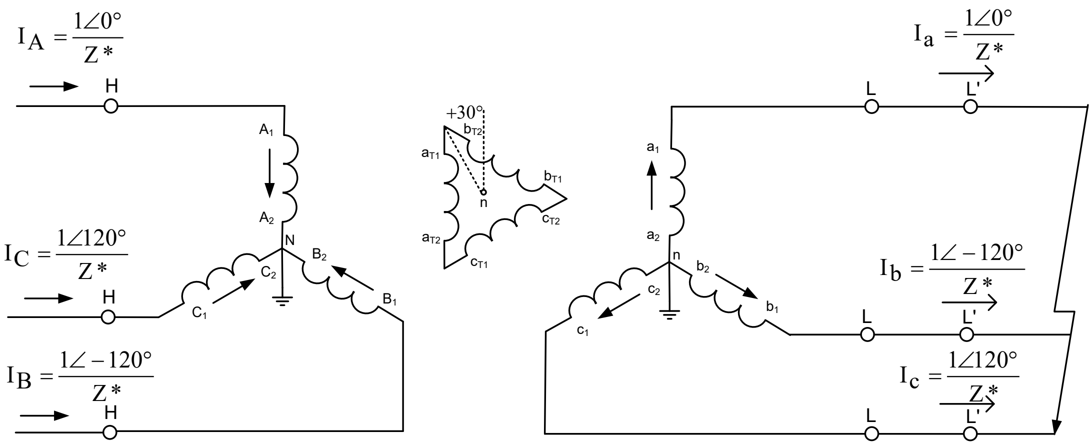
18.7.1.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z*}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{1\angle -120°}{Z*}$$

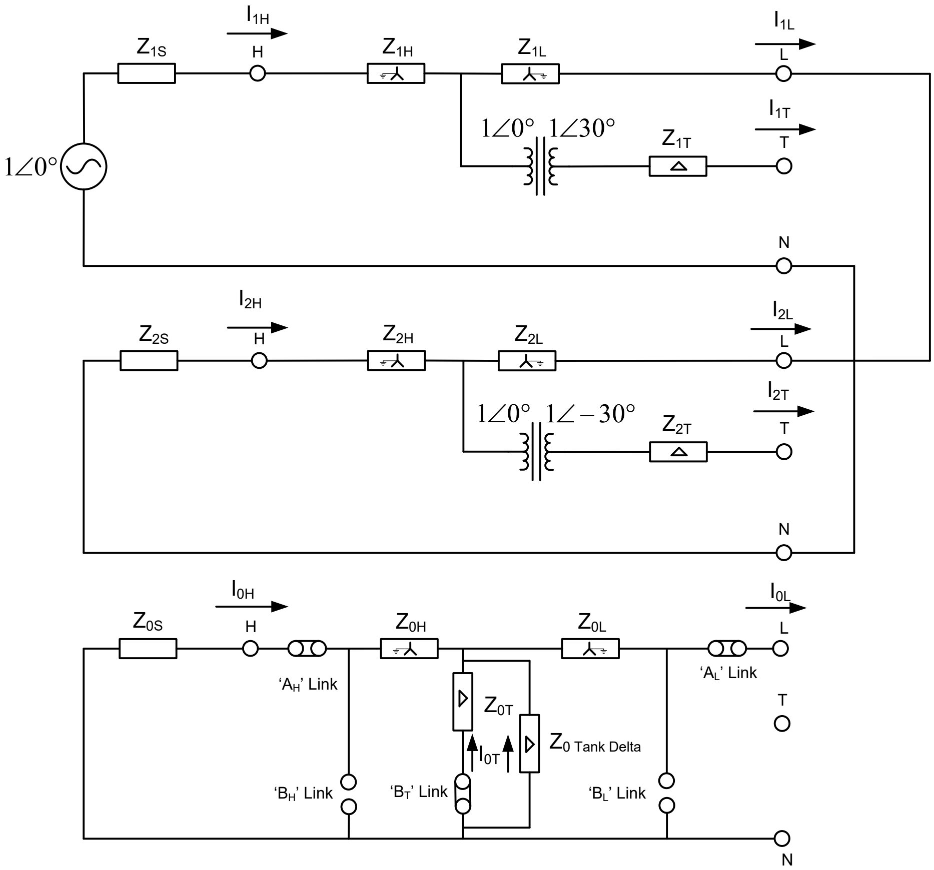
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{1\angle 120°}{Z*}$$

18.7.1.4 Phase Current Diagram



18.7.2 Phase to Phase LV Fault

18.7.2.1 Sequence Network



18.7.2.2 Sequence Currents

Define $Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z^{**}}$ $\quad$ $I_{1L} = \frac{1\angle 0°}{Z^{**}}$

$I_{2H} = \frac{-1\angle 0°}{Z^{**}}$ $\quad$ $I_{2L} = \frac{-1\angle 0°}{Z^{**}}$

$I_{0H} = 0$ $\quad$ $I_{0L} = 0$

$I_{1T} = 0$ $\quad$ $I_{2T} = 0$ $\quad$ $I_{0T} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

$I_{2H} = I_{2L}$

$I_{1H} = I_{2H}$

$I_{1L} = I_{2L}$

18.7.2.3 Phase Currents

18.7.2.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0^\circ}{Z^{**}} + \frac{-1\angle 0^\circ}{Z^{**}} = 0$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \left(\frac{(1\angle 240^\circ)(1\angle 0^\circ)}{Z^{**}}\right) + \frac{(1\angle 120^\circ)(-1\angle 0^\circ)}{Z^{**}} = \frac{\sqrt{3}\angle -90^\circ}{Z^{**}}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120^\circ)(1\angle 0^\circ)}{Z^{**}} + \frac{(1\angle 240^\circ)(-1\angle 0^\circ)}{Z^{**}} = \frac{\sqrt{3}\angle 90^\circ}{Z^{**}}$$

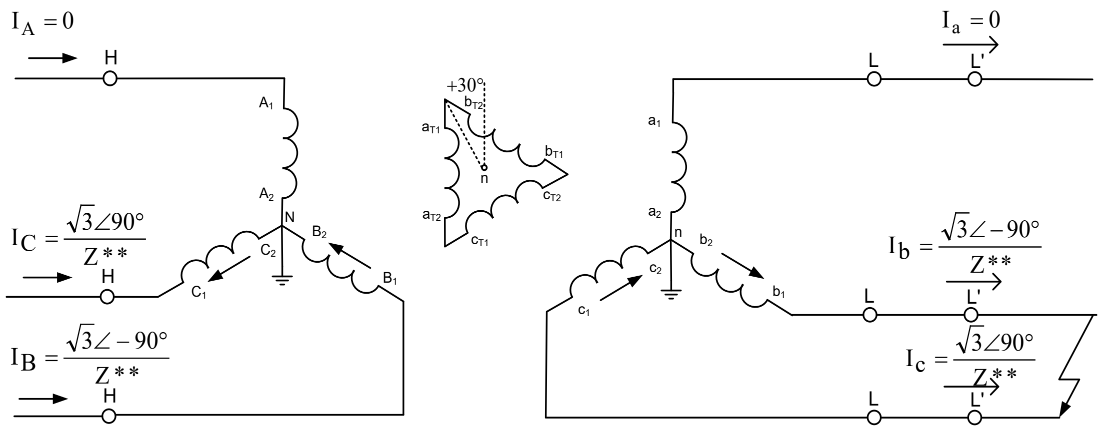
18.7.2.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0^\circ}{Z^{**}} + \frac{-1\angle 0^\circ}{Z^{**}} = 0$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240^\circ)(1\angle 0^\circ)}{Z^{**}} + \frac{(1\angle 120^\circ)(-1\angle 0^\circ)}{Z^{**}} = \frac{\sqrt{3}\angle -90^\circ}{Z^{**}}$$

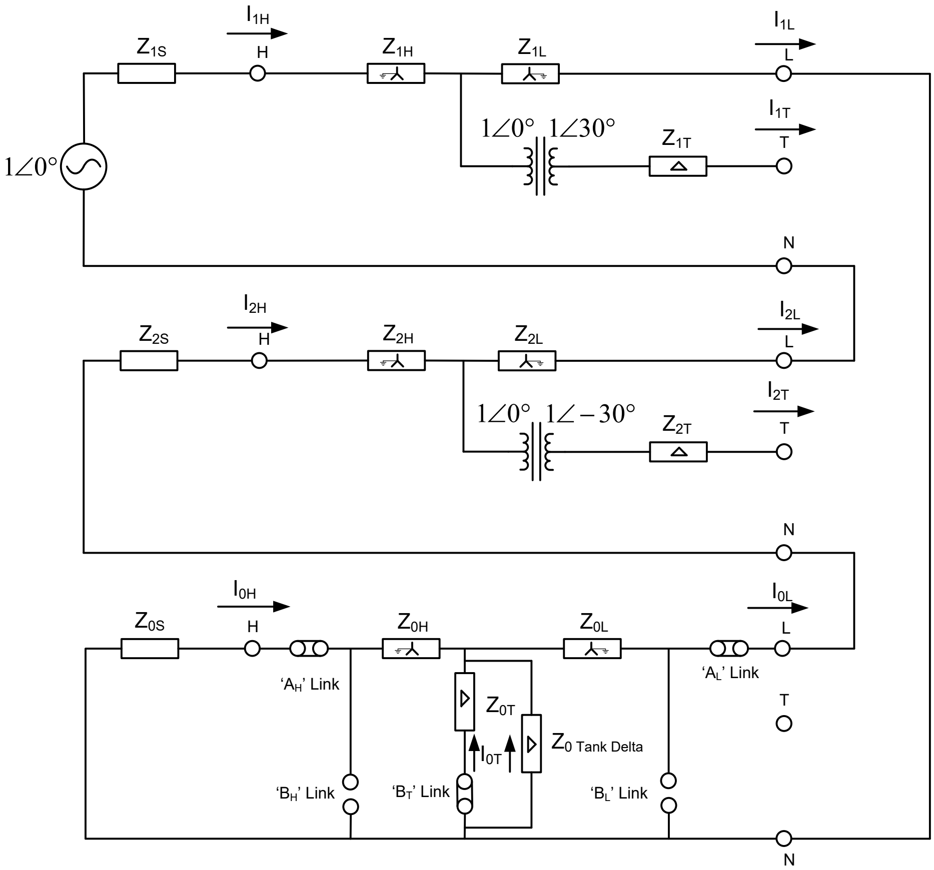
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120^\circ)(1\angle 0^\circ)}{Z^{**}} + \frac{(1\angle 240^\circ)(-1\angle 0^\circ)}{Z^{**}} = \frac{\sqrt{3}\angle 90^\circ}{Z^{**}}$$

18.7.2.4 Phase Current Diagram



18.7.3 Phase to Earth LV Fault

18.7.3.1 Sequence Network



18.7.3.2 Sequence Currents

Define Z*** $= 2(Z_{1S} + Z_{1H} + Z_{1L}) + Z_{0L} + \frac{Z_{0T}(Z_{0S}+Z_{0H})}{Z_S+Z_{0H}+Z_{0T}}$

This is the impedance used to determine the common current through the:

1) Positive sequence HV and LV Terminals

2) Negative sequence HV and LV Terminals

3) Zero sequence LV Terminals

$\frac{Z_{0T}}{Z_{0S}+Z_{0H}+Z_{0T}}$ is the current divider factor used to determine the portion of the common current that flows through the zero sequence HV Terminals.

$\frac{Z_{0S}+Z_{0H}}{Z_{0S}+Z_{0H}+Z_{0T}}$ is the current divider factor used to determine the portion of the common current that flows through the zero sequence tertiary winding.

The sequence currents can then be written as:

$$I_{1H} = \frac{1\angle 0°V}{Z^{***}} \qquad I_{1L} = \frac{1\angle 0°V}{Z^{***}}$$

$$I_{2H} = \frac{1\angle 0°V}{Z^{***}} \qquad I_{2L} = \frac{1\angle 0°V}{Z^{***}}$$

$$I_{0H} = \frac{1\angle 0°V\left(\frac{Z_{0T}}{Z_{0S}+Z_{0H}+Z_{0T}}\right)}{Z^{***}} \qquad I_{0L} = \frac{1\angle 0°V}{Z^{***}}$$

$$I_{1T} = 0 \qquad I_{2T} = 0 \qquad I_{0T} = \frac{1\angle 0°V\left(\frac{Z_{0S}+Z_{0H}}{Z_{0S}+Z_{0H}+Z_{0T}}\right)}{Z^{***}}$$

From the sequence network it can be seen that:

$$I_{1H} = I_{1L} = I_{2H} = I_{2L} = I_{0L}$$

18.7.3.3 Phase Currents

18.7.3.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{3\angle 0°}{Z^{***}}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{1\angle 0°}{Z^{***}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{***}} + \frac{(1\angle 120°)1\angle 0°}{Z^{***}} = 0$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{1\angle 0°}{Z^{***}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{***}} + \frac{(1\angle 240°)1\angle 0°}{Z^{***}} = 0$$

18.7.3.3.2 Line Currents through the HV Terminals

$$I_A = 2\left(\frac{1\angle 0°}{Z^{***}}\right) + \frac{1\angle 0°\left(\frac{Z_{0T}}{Z_{0S}+Z_{0H}+Z_{0T}}\right)}{Z^{***}} = \frac{1\angle 0°}{Z^{***}}\left(2 + \left(\frac{Z_{0T}}{Z_{0S}+Z_{0H}+Z_{0T}}\right)\right)$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = -I_{0T} = \frac{1\angle 180°}{Z^{***}}\left(\frac{Z_{0S}+Z_{0H}}{Z_{0S}+Z_{0H}+Z_{0T}}\right)$$

$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = -I_{0T} = \frac{1\angle 180°}{Z^{***}}\left(\frac{Z_{0S}+Z_{0H}}{Z_{0S}+Z_{0H}+Z_{0T}}\right)$$

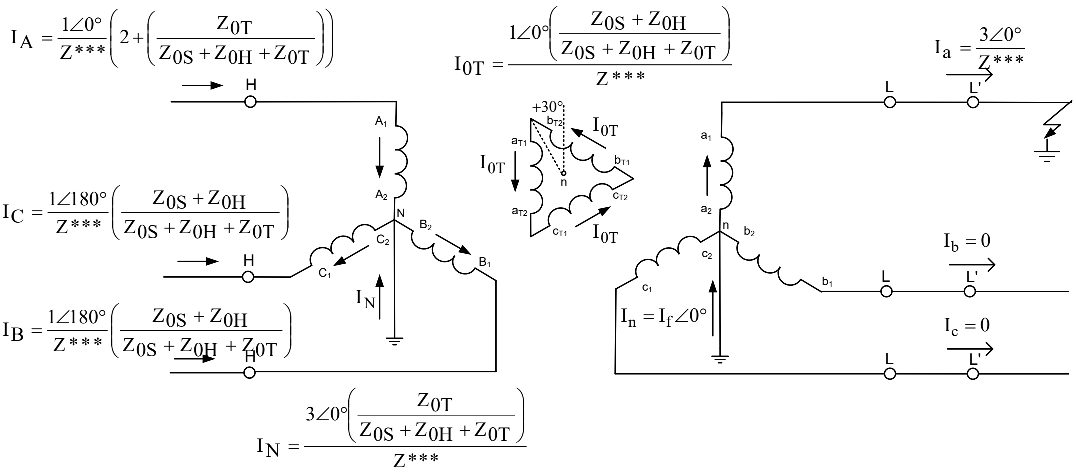
18.7.3.3.3 Current through HV Neutral

The current flowing in the HV neutral (I_N) is the portion of the zero sequence current contributed by the system (HV solidly earthed).

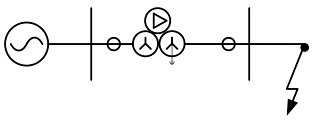
The current in the HV neutral is equal to $3I_{0H}$.

$$I_N = 3I_{0H} = \frac{3\angle 0°\left(\frac{Z_{0T}}{Z_{0S}+Z_{0H}+Z_{0T}}\right)}{Z\ ^{***}}$$

18.7.3.4 Phase Current Diagram

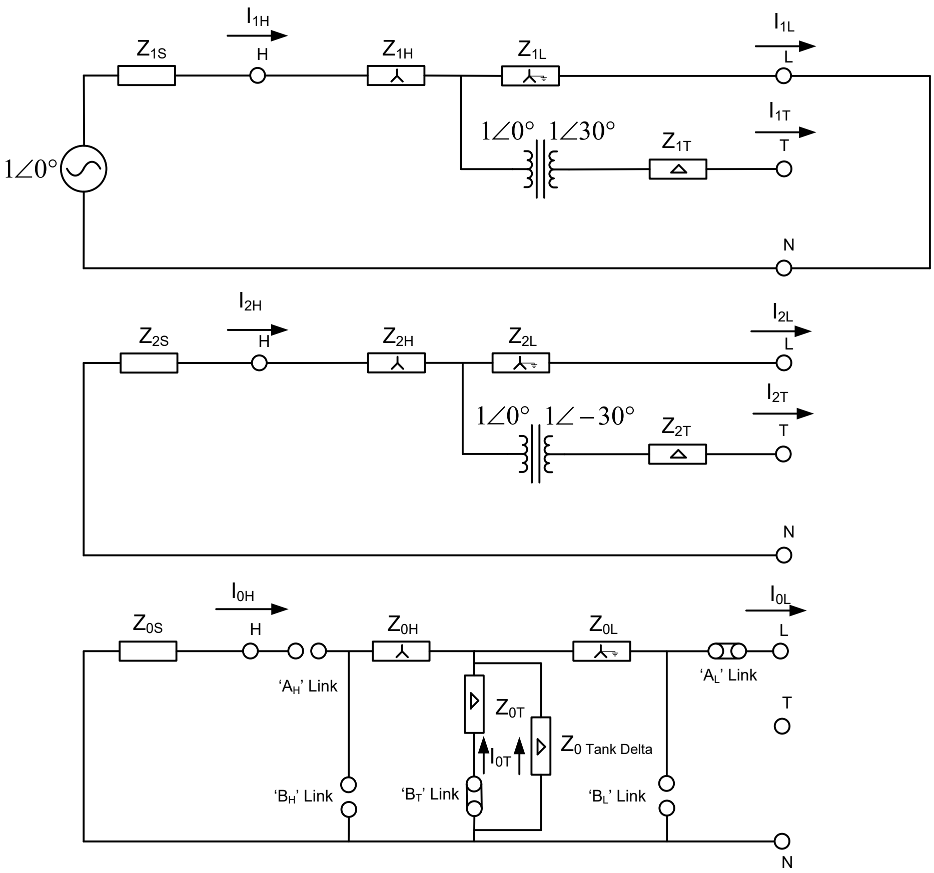


18.8 Star-Delta-Star, LV Solidly Earthed (Yd11yn)



18.8.1 Three Phase LV Fault

18.8.1.1 Sequence Network



18.8.1.2 Sequence Currents

Define $Z^* = Z_{1S} + Z_{1H} + Z_{1L}$

$I_{1H} = \frac{1}{Z^*}$ $I_{1L} = \frac{1}{Z^*}$

$I_{2H} = 0$ $I_{2L} = 0$

$I_{0H} = 0$ $I_{0L} = 0$

$I_{1T} = 0$ $I_{2T} = 0$ $I_{0T} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

18.8.1.3 Phase Currents

18.8.1.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z*}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{(1\angle -120°)}{Z*}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{(1\angle 120°)}{Z*}$$

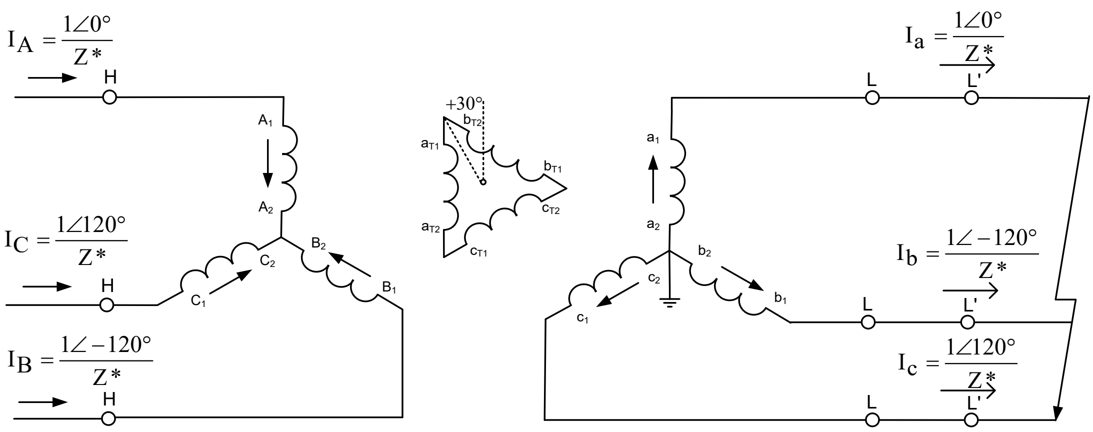
18.8.1.3.2 Line Currents through the HV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z*}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{(1\angle -120°)}{Z*}$$

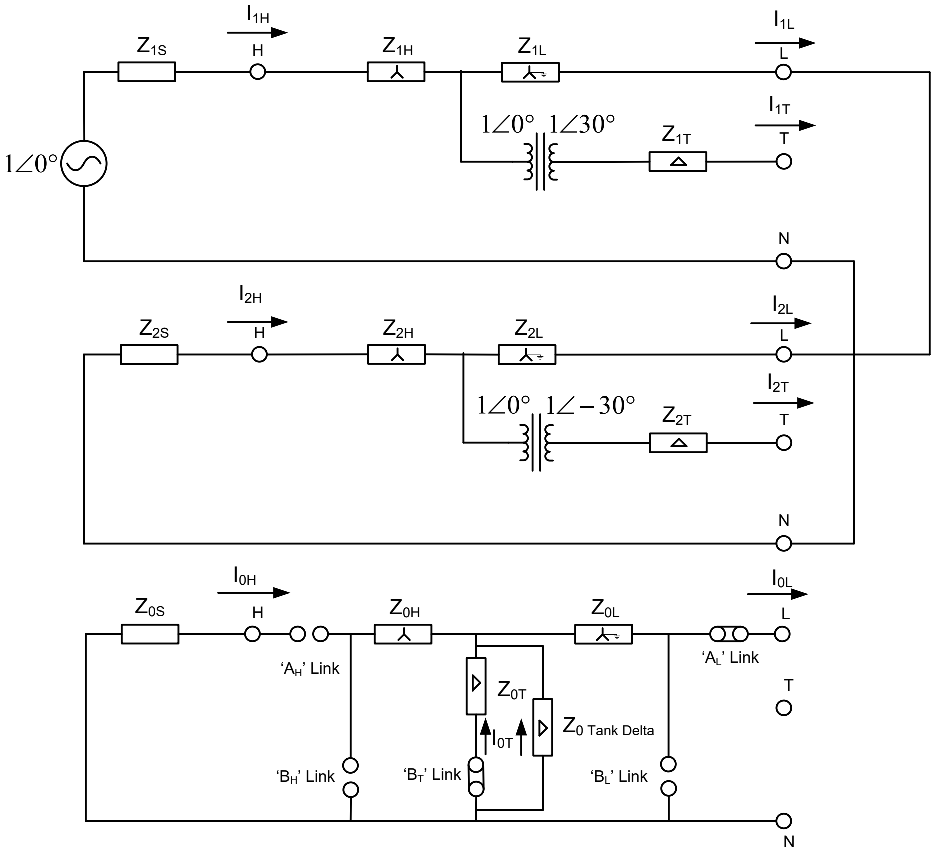
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{(1\angle 120°)}{Z*}$$

18.8.1.4 Phase Current Diagram



18.8.2 Phase to Phase LV Fault

18.8.2.1 Sequence Network



18.8.2.2 Sequence Currents

Shown with the tertiary Terminals brought out.

Define $Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z^{**}}$ $\quad$ $I_{1L} = \frac{1\angle 0°}{Z^{**}}$

$I_{2H} = \frac{-1\angle 0°}{Z^{**}}$ $\quad$ $I_{2L} = \frac{-1\angle 0°}{Z^{**}}$

$I_{0H} = 0$ $\quad$ $I_{0L} = 0$

$I_{1T} = 0$ $\quad$ $I_{2T} = 0$ $\quad$ $I_{0T} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

$I_{2H} = I_{2L}$

$I_{1H} = I_{2H}$

$I_{1L} = I_{2L}$

18.8.2.3 Phase Currents

18.8.2.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z^{**}} + \frac{-1\angle 0°}{Z^{**}} = 0$$

$$I_b = I_{0L} + a^2 I_{1L} + \mathrm{al}_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 120°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle -90°}{Z^{**}}$$

$$I_c = I_{0L} + \mathrm{al}_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 240°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle 90°}{Z^{**}}$$

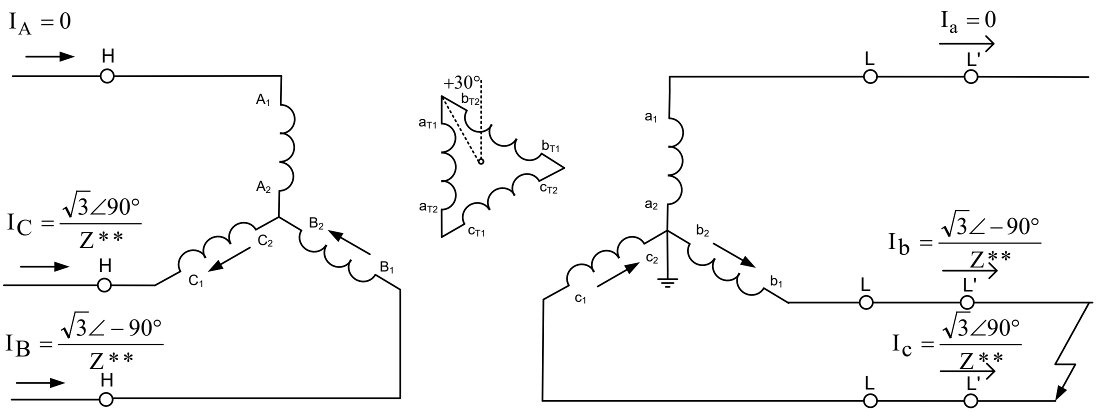
18.8.2.3.2 Line Currents through the HV Terminals

$$I_A = (I_{0H} + I_{1H} + I_{2H}) = \frac{1\angle 0°}{Z^{**}} + \frac{-1\angle 0°}{Z^{**}} = 0$$

$$I_B = I_{0H} + a^2 I_{1H} + \mathrm{al}_{1H} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 120°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle -90°}{Z^{**}}$$

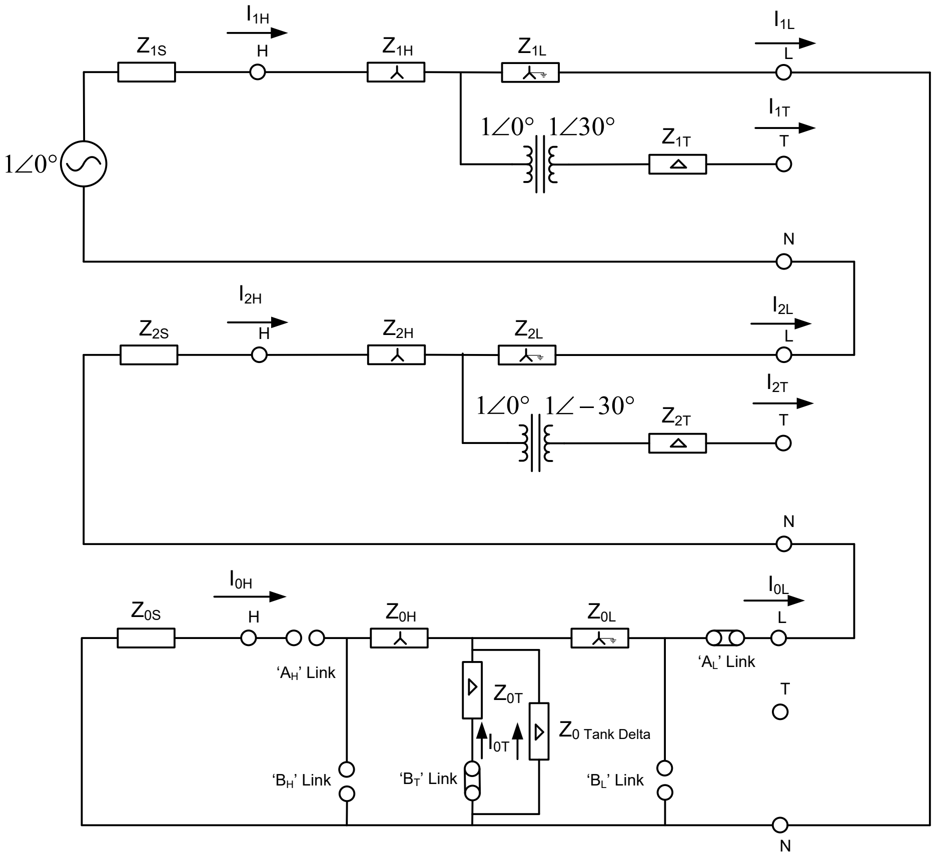
$$I_C = I_{0H} + \mathrm{al}_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 240°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle 90°}{Z^{**}}$$

18.8.2.4 Phase Current Diagram



18.8.3 Phase to Earth LV Fault

18.8.3.1 Sequence Network



18.8.3.2 Sequence Currents

Define $Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$$I_{1H} = \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}} \qquad I_{1L} = \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}}$$

$$I_{2H} = \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}} \qquad I_{2L} = \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}}$$

$$I_{0H} = 0 \qquad I_{0L} = \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}}$$

$$I_{1T} = 0 \qquad I_{2T} = 0 \qquad I_{0T} = \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}}$$

From the sequence network it can be seen that:

$$I_{1H} = I_{1L} = I_{2H} = I_{2L} = I_{0L} = I_{0T}$$

18.8.3.3 Phase Currents

18.8.3.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{3\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0L} + Z_{0T}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0L} + Z_{0T}} = 0$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0L} + Z_{0T}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0L} + Z_{0T}} = 0$$

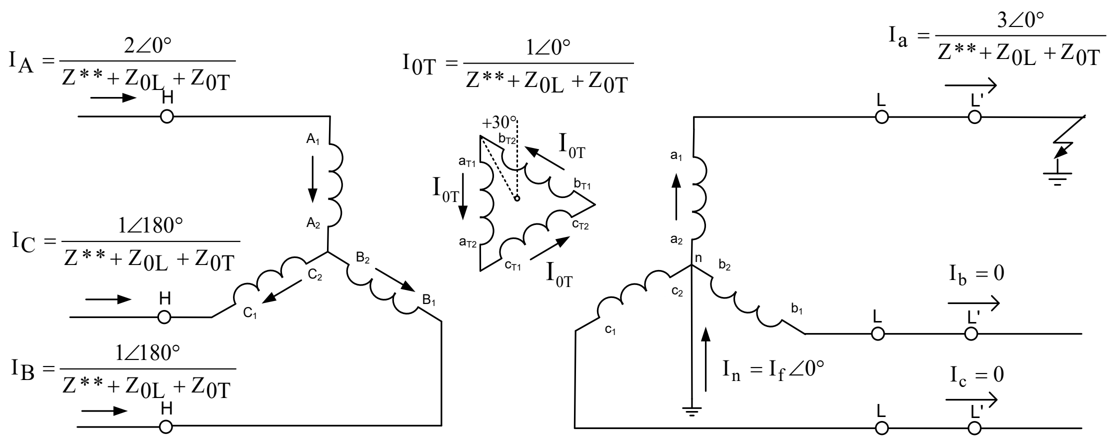
18.8.3.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}} + \frac{1\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}} = \frac{2\angle 0°}{Z^{**} + Z_{0L} + Z_{0T}}$$

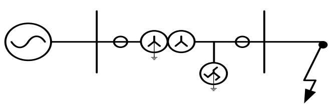
$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0L} + Z_{0T}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0L} + Z_{0T}} = \frac{1\angle 180°}{Z^{**} + Z_{0L} + Z_{0T}}$$

$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0L} + Z_{0T}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0L} + Z_{0T}} = \frac{1\angle 180°}{Z^{**} + Z_{0L} + Z_{0T}}$$

18.8.3.4 Phase Current Diagram

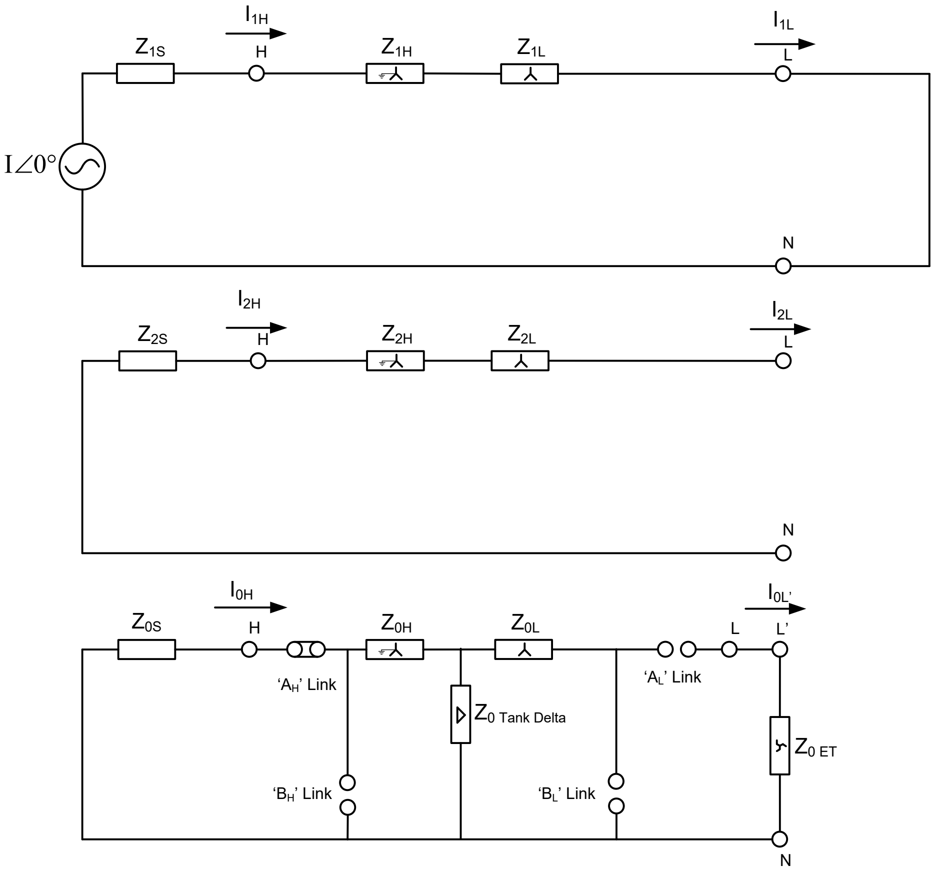


18.9 Star-Star, HV Solidly Earthed, LV Earthing Transformer (Yny0+zn)



18.9.1 Three Phase LV Fault

18.9.1.1 Sequence Network



18.9.1.2 Sequence Currents

Define $Z^* = Z_{1S} + Z_{1H} + Z_{1L}$

$I_{1H} = \frac{1\angle 0°}{Z^*}$ $\quad$ $I_{1L} = \frac{1\angle 0°}{Z^*}$

$I_{2H} = 0$ $\quad$ $I_{2L} = 0$

$I_{0H} = 0$ $\quad$ $I_{0L} = 0$ $\quad$ $I_{0L'} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

18.9.1.3 Phase Currents

18.9.1.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z*}$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{(1\angle -120°)}{Z*}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{(1\angle 120°)}{Z*}$$

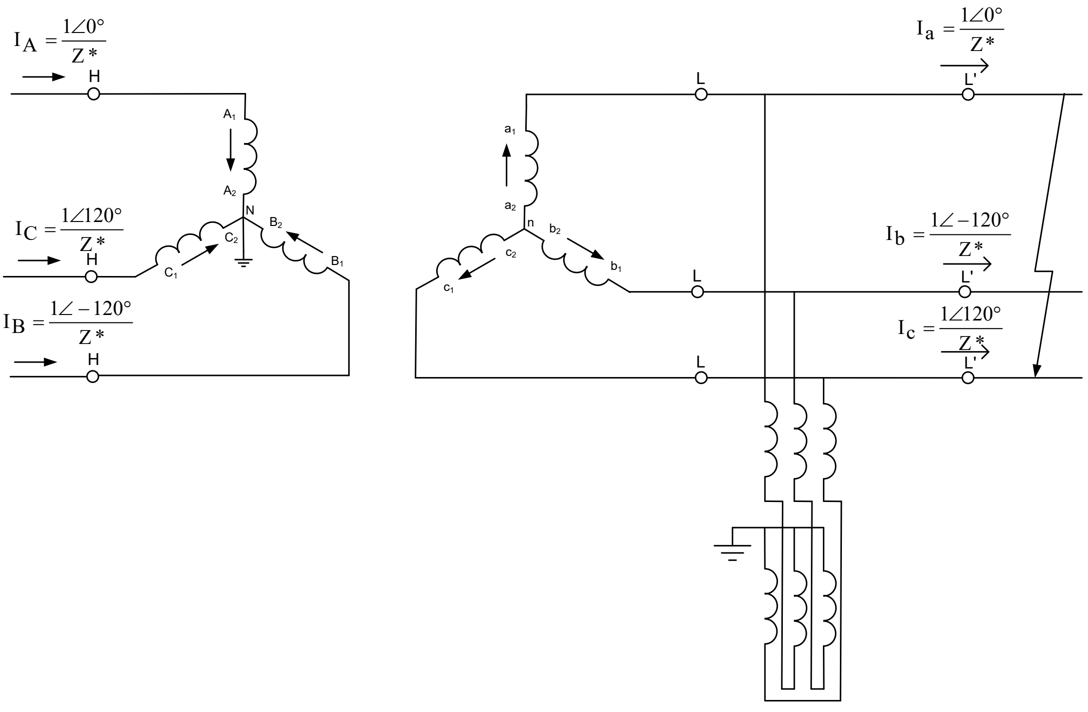
18.9.1.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z*}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z*} = \frac{(1\angle -120°)}{Z*}$$

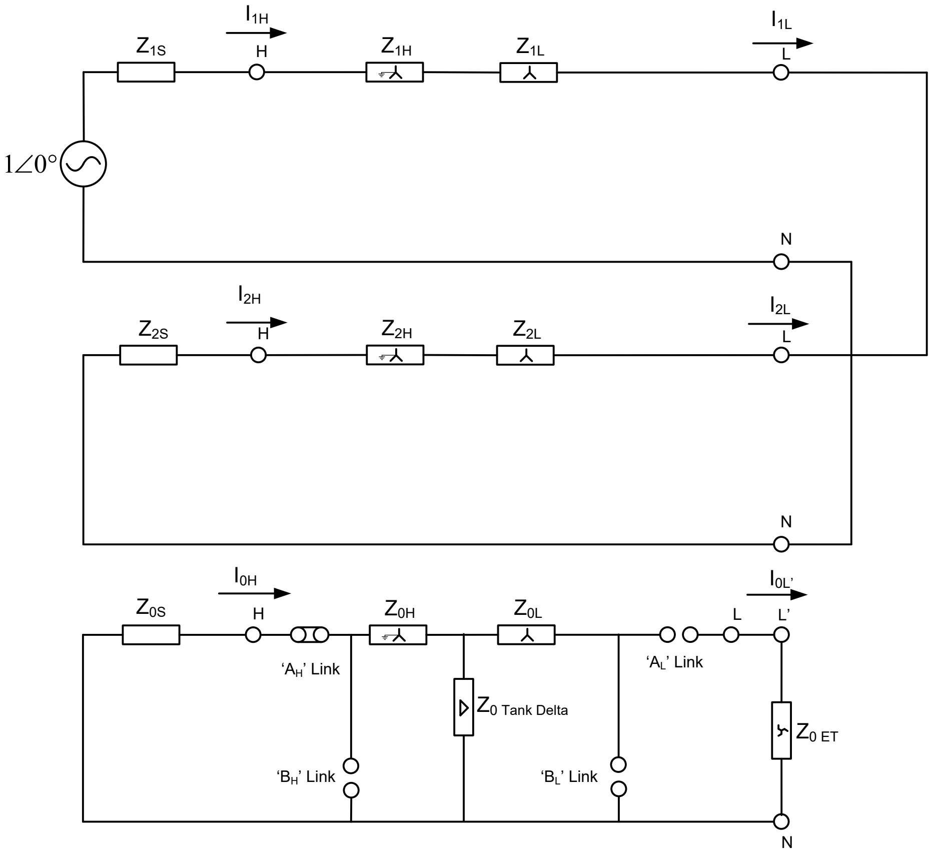
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z*} = \frac{(1\angle 120°)}{Z*}$$

18.9.1.4 Phase Current Diagram



18.9.2 Phase to Phase LV Fault

18.9.2.1 Sequence Network



18.9.2.2 Sequence Currents

Define$Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z^{**}}$ $\qquad$ $I_{1L} = \frac{1\angle 0°}{Z^{**}}$

$I_{2H} = \frac{-1\angle 0°}{Z^{**}}$ $\qquad$ $I_{2L} = \frac{-1\angle 0°}{Z^{**}}$

$I_{0H} = 0$ $\qquad$ $I_{0L} = 0$ $\qquad$ $I_{0L'} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{1L}$

$I_{2H} = I_{2L}$

$I_{1H} = I_{2H}$

$I_{1L} = I_{2L}$

18.9.2.3 Phase Currents

18.9.2.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z^{**}} + \frac{-1\angle 0°}{Z^{**}} = 0$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 120°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle -90°}{Z^{**}}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 240°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle 90°}{Z^{**}}$$

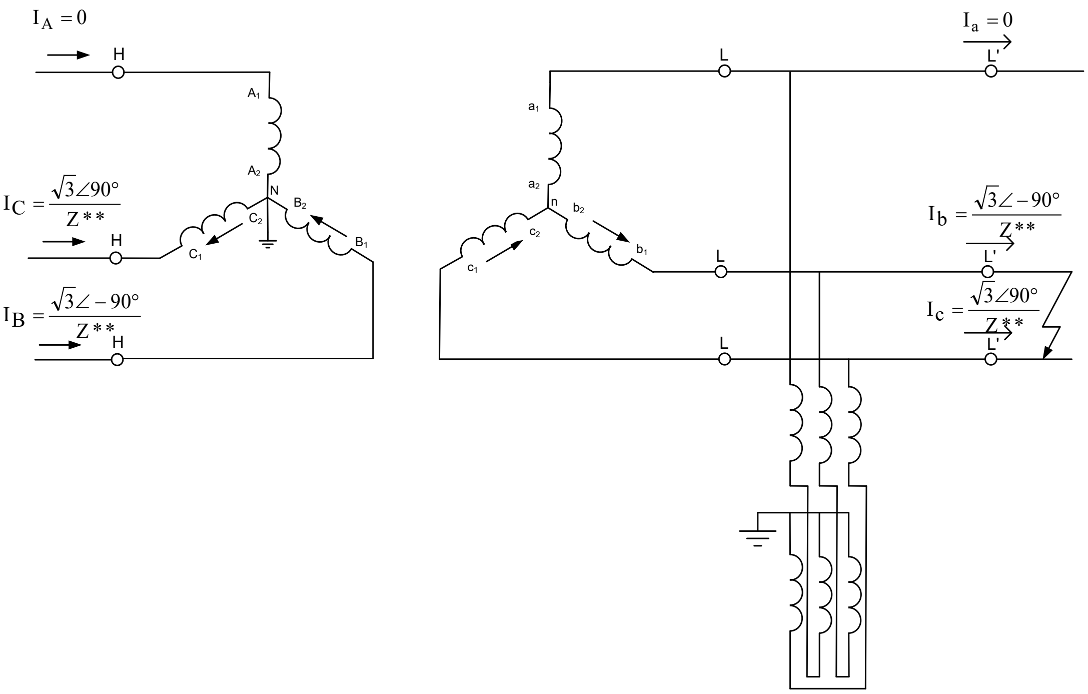
18.9.2.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z^{**}} + \frac{-1\angle 0°}{Z^{**}} = 0$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 120°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle -90°}{Z^{**}}$$

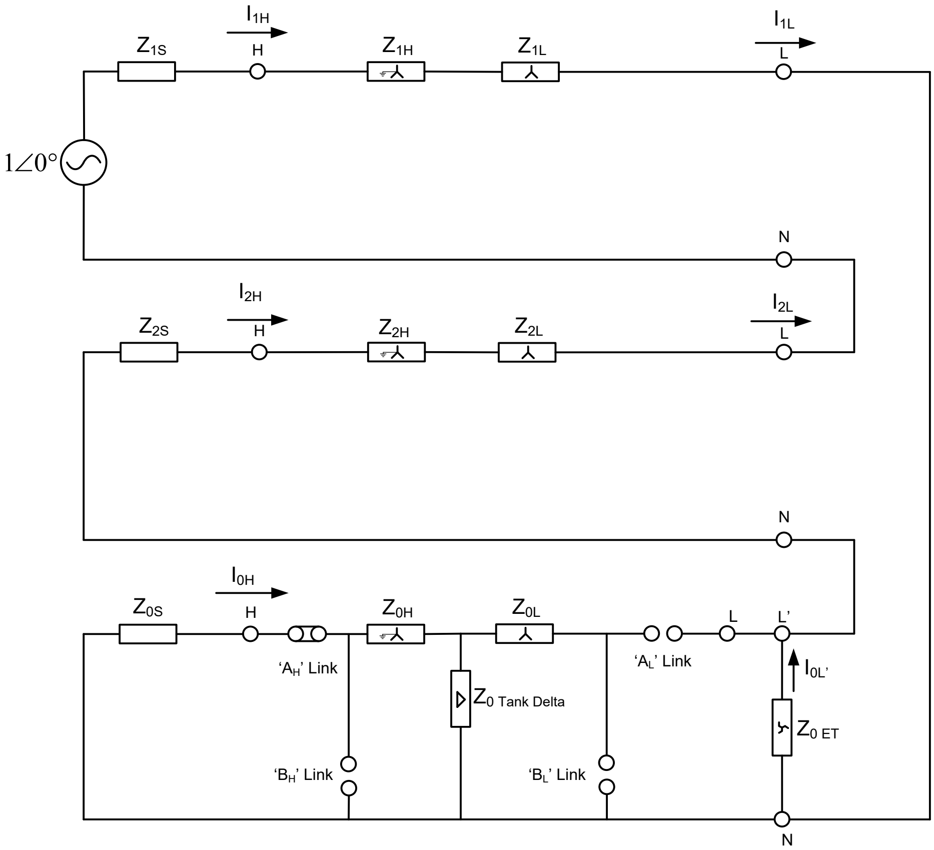
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**}} + \frac{(1\angle 240°)(-1\angle 0°)}{Z^{**}} = \frac{\sqrt{3}\angle 90°}{Z^{**}}$$

18.9.2.4 Phase Current Diagram



18.9.3 Phase to Earth LV Fault

18.9.3.1 Sequence Network



18.9.3.2 Sequence Currents

Define Z** $= Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0° V}{Z^{**} + Z_{0\ ET}}$ $\quad$ $I_{1L} = \frac{1\angle 0° V}{Z^{**} + Z_{0\ ET}}$

$I_{2H} = \frac{1\angle 0° V}{Z^{**} + Z_{0\ ET}}$ $\quad$ $I_{2L} = \frac{1\angle 0° V}{Z^{**} + Z_{0\ ET}}$

$I_{0H} = 0$ $\quad$ $I_{0L} = 0$ $\quad$ $I_{0L'} = \frac{1\angle 0° V}{Z^{**} + Z_{0\ ET}}$

From the sequence network it can be seen that:

$I_{1H} = I_{1L} = I_{2H} = I_{2L} = I_{0L'}$

18.9.3.3 Phase Currents

18.9.3.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{3\angle 0°}{Z^{**} + Z_{0\,ET}}$$

$$I_b = I_{0L} + a^2 I_{1L} + \mathrm{al}_{2L} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0\,ET}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0\,ET}} = \frac{1\angle 180°}{Z^{**} + Z_{0\,ET}}$$

$$I_c = I_{0L} + \mathrm{al}_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0\,ET}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0\,ET}} = \frac{1\angle 180°}{Z^{**} + Z_{0\,ET}}$$

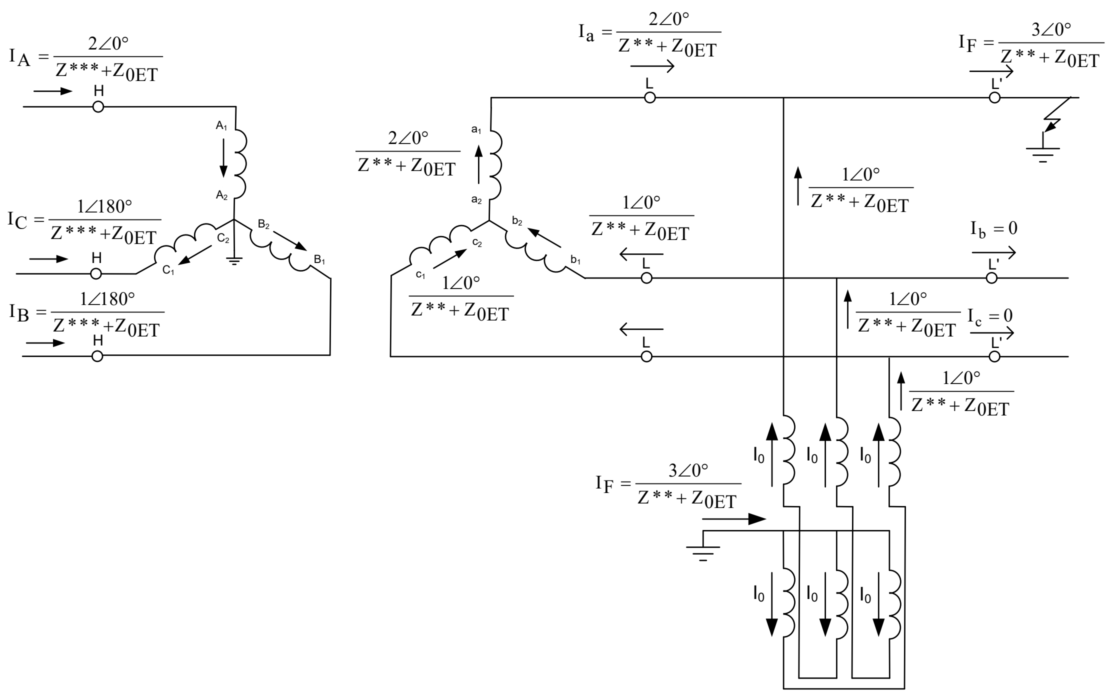
18.9.3.3.2 Line Currents through the HV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle 0°}{Z^{**} + Z_{0\,ET}} + \frac{1\angle 0°}{Z^{**} + Z_{0\,ET}} = \frac{2\angle 0°}{Z^{**} + Z_{0\,ET}}$$

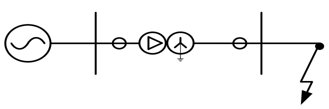
$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0\,ET}} + \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0\,ET}} = \frac{1\angle 180°}{Z^{**} + Z_{0\,ET}}$$

$$I_C = I_{0H} + \mathrm{al}_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0\,ET}} + \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0\,ET}} = \frac{1\angle 180°}{Z^{**} + Z_{0\,ET}}$$

18.9.3.4 Phase Current Diagram

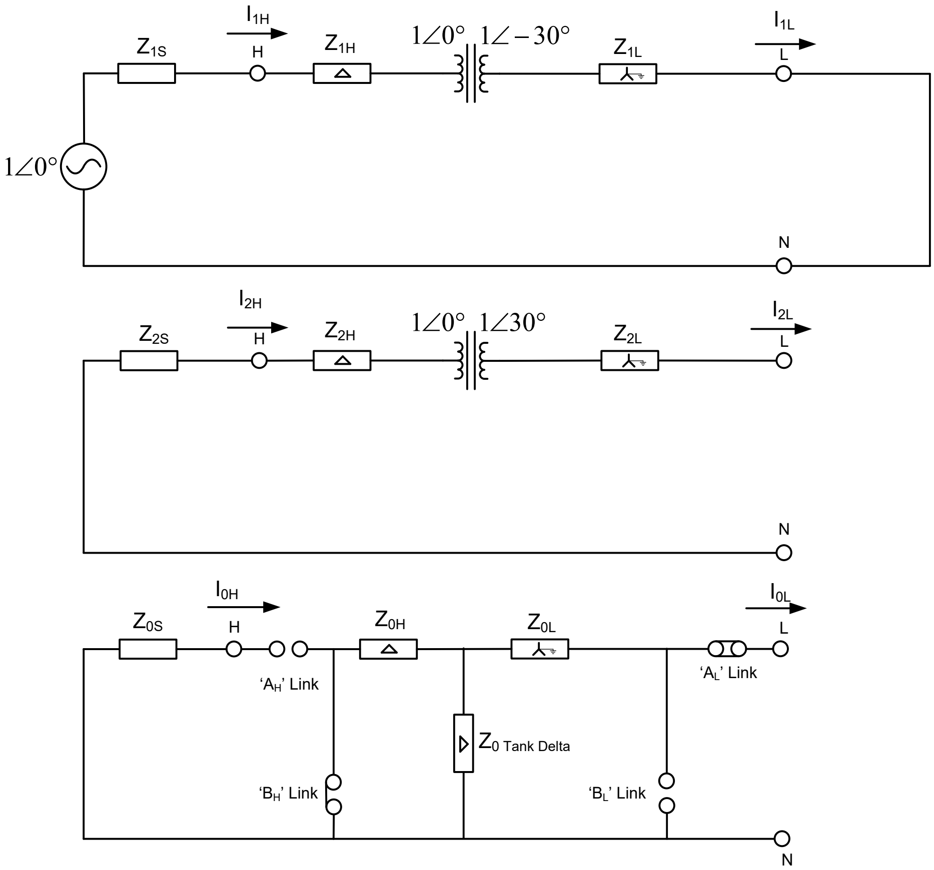


18.10 Delta-Star (D11yn)



18.10.1 Three Phase LV Fault

18.10.1.1 Sequence Network



18.10.1.2 Sequence Currents

Define $Z^* = Z_{1S} + Z_{1H} + Z_{1L}$

$I_{1H} = \frac{1\angle 0°}{Z^*}$ $\qquad$ $I_{1L} = \frac{1\angle -30°}{Z^*}$

$I_{2H} = 0$ $\qquad$ $I_{2L} = 0$

$I_{0H} = 0$ $\qquad$ $I_{0L} = 0$

18.10.1.3 Phase Currents

18.10.1.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle -30°}{Z^*}$$

$$I_b = I_{0L} + a^2 I_{1L} + I_{2L} = \frac{(1\angle 240°)(1\angle -30°)}{Z^*} = \frac{(1\angle -150°)}{Z^*}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle 30°)}{Z^*} = \frac{(1\angle 90°)}{Z^*}$$

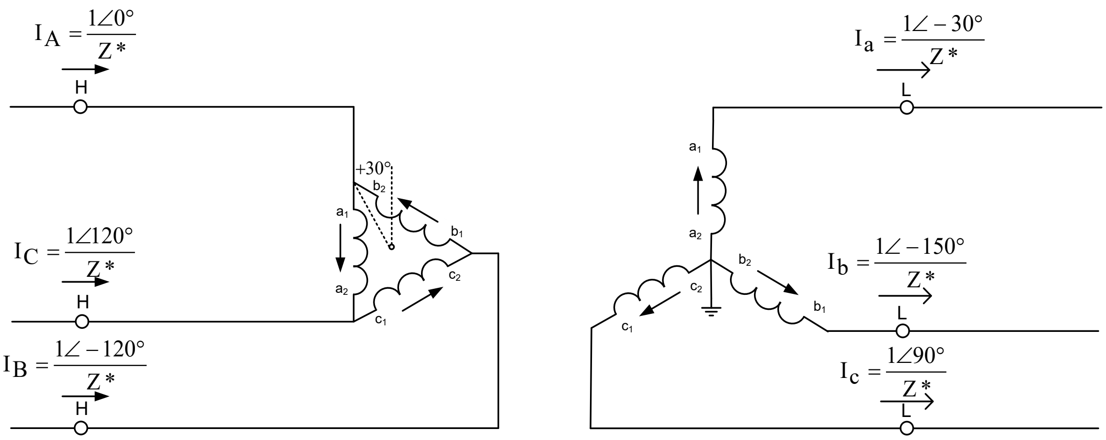
18.10.1.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z^*}$$

$$I_B = I_{0H} + a^2 I_{1H} + I_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z^*} = \frac{1\angle -120°}{Z^*}$$

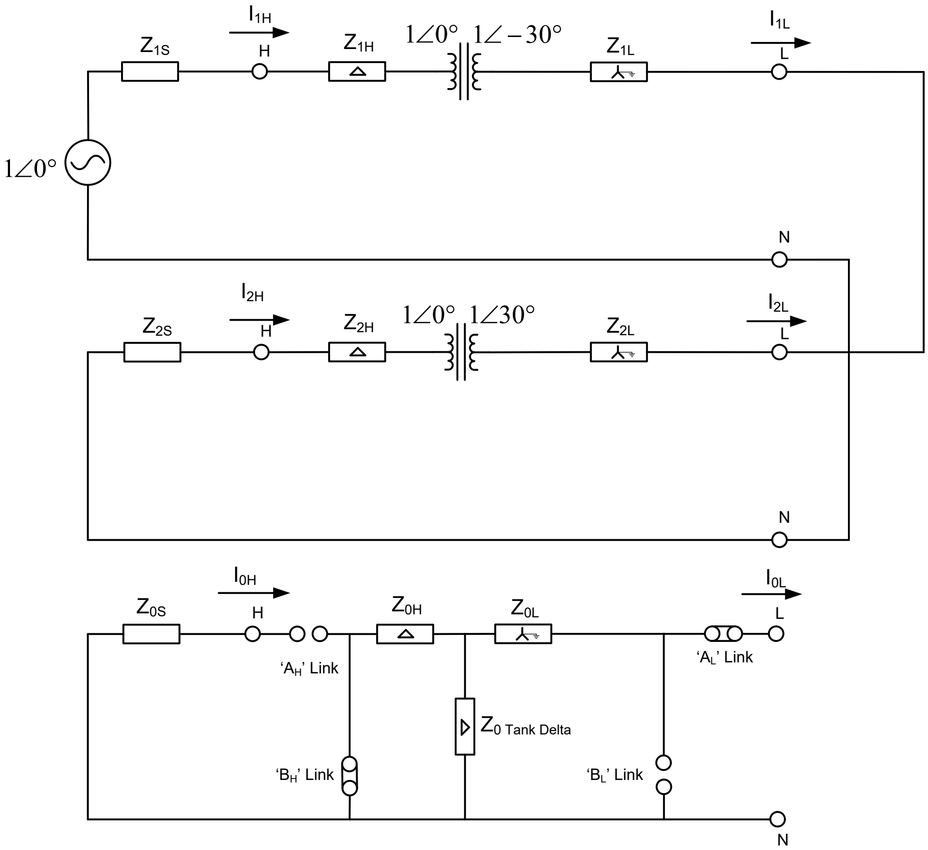
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z^*} = \frac{(1\angle 120°)}{Z^*}$$

18.10.1.4 Phase Current Diagram



18.10.2 Phase to Phase LV Fault

18.10.2.1 Sequence Network



18.10.2.2 Sequence Currents

Define $Z^{**} = Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0^\circ}{Z^{**}}$ $\quad$ $I_{1L} = \frac{1\angle -30^\circ}{Z^{**}}$

$I_{2H} = \frac{-1\angle -60^\circ}{Z^{**}}$ $\quad$ $I_{2L} = \frac{-1\angle -30^\circ}{Z^{**}}$

$I_{0H} = 0$ $\quad$ $I_{0L} = 0$

From the sequence network it can be seen that:

$I_{1H} = I_{2H}$

$I_{1L} = I_{2L}$

18.10.3 Phase Currents

18.10.3.1.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{1\angle -30°}{Z**} + \frac{-1\angle -30°}{Z**} = 0$$

$$I_b = I_{0L} + a^2 I_{1L} + aI_{2L} = \frac{(1\angle 240°)(1\angle -30°)}{Z**} + \frac{(1\angle 120°)(-1\angle -30°)}{Z**} = \frac{\sqrt{3}\angle -120}{Z**}$$

$$I_c = I_{0L} + aI_{1L} + a^2 I_{2L} = \frac{(1\angle 120°)(1\angle -30°)}{Z**} + \frac{(1\angle 240°)(-1\angle -30°)}{Z**} = \frac{\sqrt{3}\angle 60°}{Z**}$$

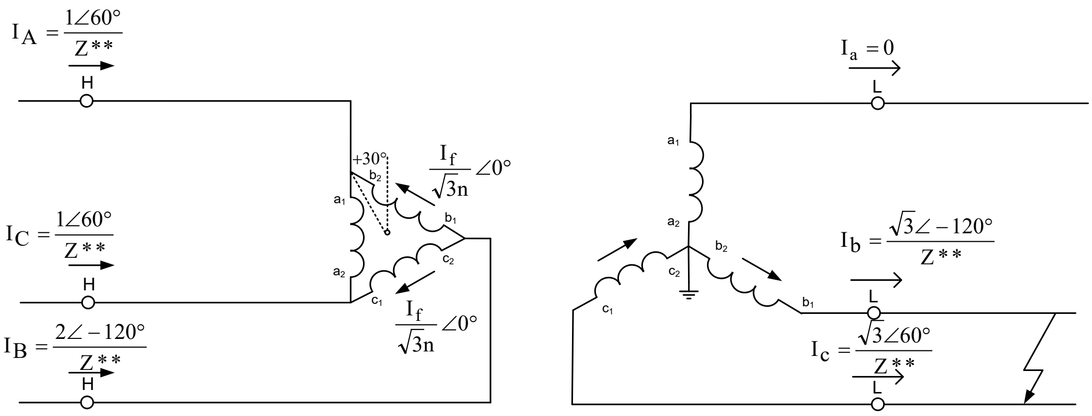
18.10.3.1.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z**} + \frac{-1\angle -60°}{Z**} = \frac{1\angle 60°}{Z**}$$

$$I_B = I_{0H} + a^2 I_{1H} + aI_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z**} + \frac{(1\angle 120°)(-1\angle -60°)}{Z**} = \frac{2\angle -120°}{Z**}$$

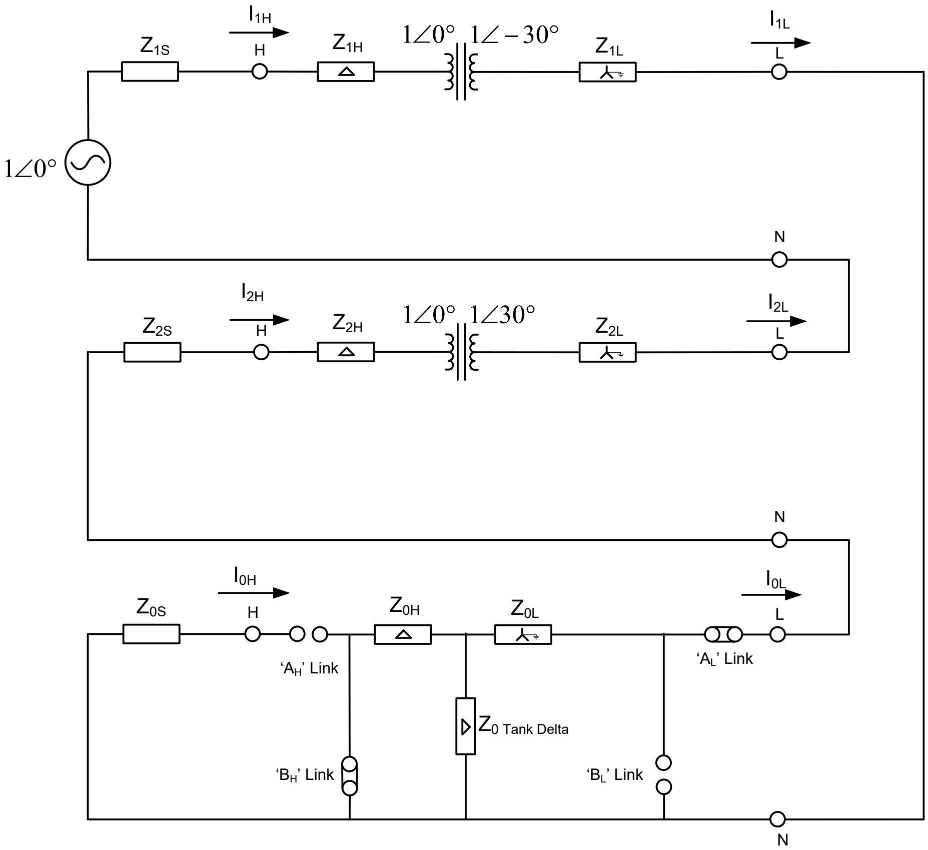
$$I_C = I_{0H} + aI_{1H} + a^2 I_{2H} = 0 + \frac{(1\angle 120°)(1\angle 0°)}{Z**} + \frac{(1\angle 240°)(-1\angle -60°)}{Z**} = \frac{1\angle 60°}{Z**}$$

18.10.3.2 Phase Current Diagram



18.10.4 Phase to Earth LV Fault

18.10.4.1 Sequence Network



18.10.4.2 Sequence Currents

Define Z** $= Z_{1S} + Z_{1H} + Z_{1L} + Z_{2S} + Z_{2H} + Z_{2L}$

$I_{1H} = \frac{1\angle 0°}{Z^{**} + Z_{0H} + Z_{0L}}$ $\quad I_{1L} = \frac{1\angle -30°}{Z^{**} + Z_{0H} + Z_{0L}}$

$I_{2H} = \frac{1\angle -60°}{Z^{**} + Z_{0H} + Z_{0L}}$ $\quad I_{2L} = \frac{1\angle -30°}{Z^{**} + Z_{0H} + Z_{0L}}$

$I_{0H} = 0$ $\quad I_{0L} = \frac{1\angle -30°}{Z^{**} + Z_{0H} + Z_{0L}}$

From the sequence network it can be seen that:

$I_{0L} = I_{1L} = I_{2L}$

18.10.4.3 Phase Currents

18.10.4.3.1 Line Currents through the LV Terminals

$$I_a = I_{0L} + I_{1L} + I_{2L} = \frac{3\angle -30°}{Z^{**} + Z_{0H} + Z_{0L}}$$

$$I_b = I_{0L} + a^2 I_{1L} + \mathrm{a} I_{2L} = \frac{(1\angle 0°)}{Z^{**} + Z_{0H} + Z_{0L}} + \frac{(1\angle 240°)(1\angle -30°)}{Z^{**} + Z_{0H} + Z_{0L}} + \frac{(1\angle 120°)(1\angle -30°)}{Z^{**} + Z_{0H} + Z_{0L}} = 0$$

$$I_c = I_{0L} + a^2 I_{1L} + \mathrm{a} I_{2L} = \frac{(1\angle 0°)}{Z^{**} + Z_{0H} + Z_{0L}} + \frac{(1\angle 120°)(1\angle -30°)}{Z^{**} + Z_{0H} + Z_{0L}} + \frac{(1\angle 240°)(1\angle -30°)}{Z^{**} + Z_{0H} + Z_{0L}} = 0$$

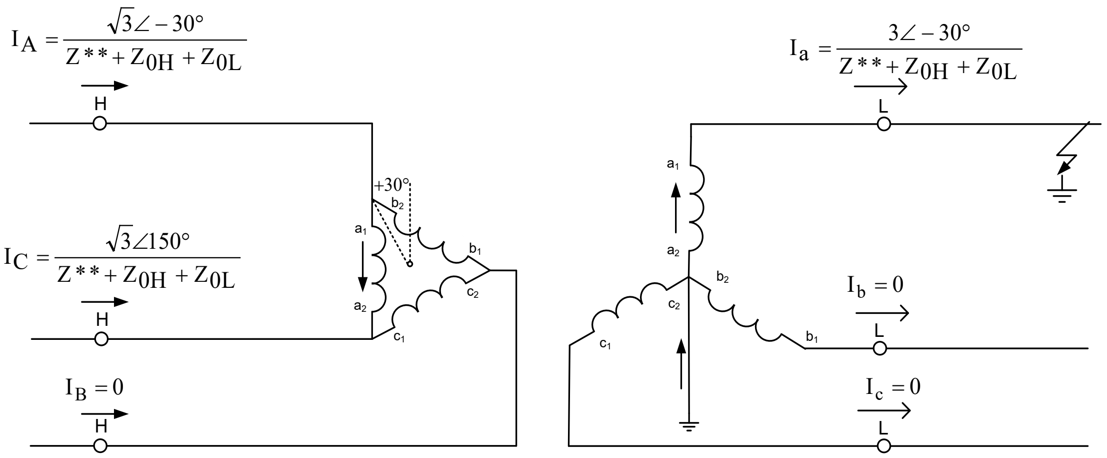
18.10.4.3.2 Line Currents through the HV Terminals

$$I_A = I_{0H} + I_{1H} + I_{2H} = \frac{1\angle 0°}{Z^{**} + Z_{0H} + Z_{0L}} + \frac{1\angle -60°}{Z^{**} + Z_{0H} + Z_{0L}} = \frac{\sqrt{3}\angle -30°}{Z^{**} + Z_{0H} + Z_{0L}}$$

$$I_B = I_{0H} + a^2 I_{1H} + \mathrm{a} I_{2H} = \frac{(1\angle 240°)(1\angle 0°)}{Z^{**} + Z_{0H} + Z_{0L}} + \frac{(1\angle 120°)(1\angle -60°)}{Z^{**} + Z_{0H} + Z_{0L}} = 0$$

$$I_C = I_{0H} + \mathrm{a} I_{1H} + a^2 I_{2H} = \frac{(1\angle 120°)(1\angle 0°)}{Z^{**} + Z_{0H} + Z_{0L}} + \frac{(1\angle 240°)(1\angle -60°)}{Z^{**} + Z_{0H} + Z_{0L}} = \frac{\sqrt{3}\angle 150°}{Z^{**} + Z_{0H} + Z_{0L}}$$

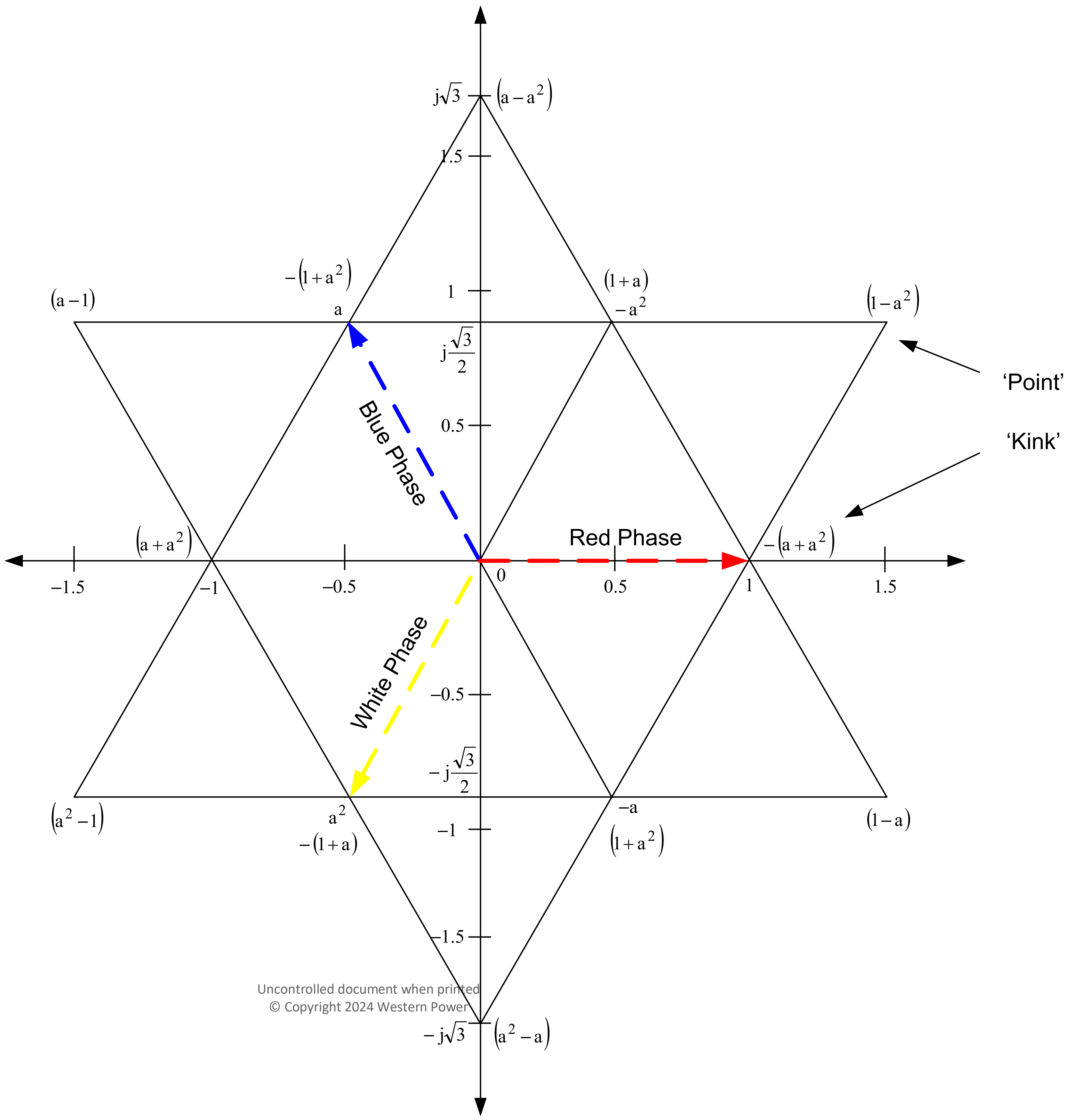
18.10.4.4 Phase Current Diagram



18.11 Appendix A – ‘a’ Operator

Figure 4.1.1.1 summarises the sequence network operator ‘a’.

Figure 18.11 – ‘a’ operator



All ‘points’ have a magnitude of √3 and are spaced at 60° intervals starting from +30° (e.g. $(1 - a^2) = \sqrt{3}\angle 30°$). All ‘kinks’ have a magnitude of 1 and are spaced at 60° intervals starting from $-(a + a^2) = 1\angle 0°$.

18.12 Appendix B – Common Notation

Table 18.1 – Common Notation

Notation	Meaning
I_A	Line current through the HV Terminals of the A phase
I_a	Line current through the LV Terminals of the A phase
I_{aT}	Phase current through the A phase tertiary winding
I_{1H}	Positive sequence current through the HV Terminals
I_{2H}	Negative sequence current through the HV Terminals
I_{0H}	Zero sequence current through the HV Terminals
Z_{1S}	Positive sequence source impedance
Z_{2S}	Negative sequence source impedance
Z_{0S}	Zero sequence source impedance
Z_{0T}	Zero sequence tertiary impedance
I_F	Fault current

18.13 Appendix C – Per Unit

18.13.1 Per Unit Base Values

$V_{Base} = V_{line}$

$$I_{\text{Base}} = \frac{S_{\text{Base}}}{\sqrt{3}V_{\text{Base}}}\ \text{kA}$$

$$Z_{\text{Base}} = \frac{{V_{\text{Base}}}^2}{\text{MVA}_{\text{Base}}}\Omega$$

18.13.2 Equations

Total Apparent 3 Phase Power, S $= 3xV_{ph}xI_{ph} = \sqrt{3}(V_{line}xI_{line})$

Western Power has selected 100 MVA as its base 3 phase power, thus:

$$I_{actual}(kA) = I_{pu}\frac{100MVA}{\sqrt{3}V_{line}(kV)}$$

18.13.3 Example

Determine the actual phase currents for an LV earth fault on a 132 / 22 kV YNd11 + zn transformer (refer to section 18.4.3.4).

1) System Information:

a) Z** = 0.985 pu

b) Z_{ET} = 36 Ω = 7.438 pu

18.13.3.1 Line Currents through the LV Terminals

$$I_{F_{\mathrm{pu}}} = \frac{3\angle 30°}{Z ** + Z_{ET}} = \frac{3\angle 30°}{(0.985 + 7.438)} = 0.357\angle 30° pu$$

$$I_{F\,\mathrm{line}} = (0.357\angle 30° pu)\left(\frac{100MVA}{\sqrt{3}22kV}\right) = 0.936\angle 30°\mathrm{kA}$$

$$I_{a_{\mathrm{pu}}} = \frac{2\angle 30°}{Z ** + Z_{ET}} = \frac{2\angle 30°}{(0.985 + 7.438)} = 0.238\angle 30° pu$$

$$I_{a\,\mathrm{line}} = (0.238\angle 30° pu)\left(\frac{100MVA}{\sqrt{3}22kV}\right) = 0.625\angle 30°\mathrm{kA}$$

$$I_{b_{\mathrm{pu}}} = I_{c_{\mathrm{pu}}} = \frac{1\angle 30°}{\mathrm{Z}** + Z_{\mathrm{ET}}} = \frac{1\angle 30°}{(0.985 + 7.438)} = 0.119\angle 30°\mathrm{pu}$$

$$I_{b_{\mathrm{line}}} = I_{c_{\mathrm{line}}} = (0.119\angle 30° pu)\left(\frac{100MVA}{\sqrt{3}22kV}\right) = 0.313\angle 30°\mathrm{kA}$$

18.13.3.2 Line Currents through the HV Terminals

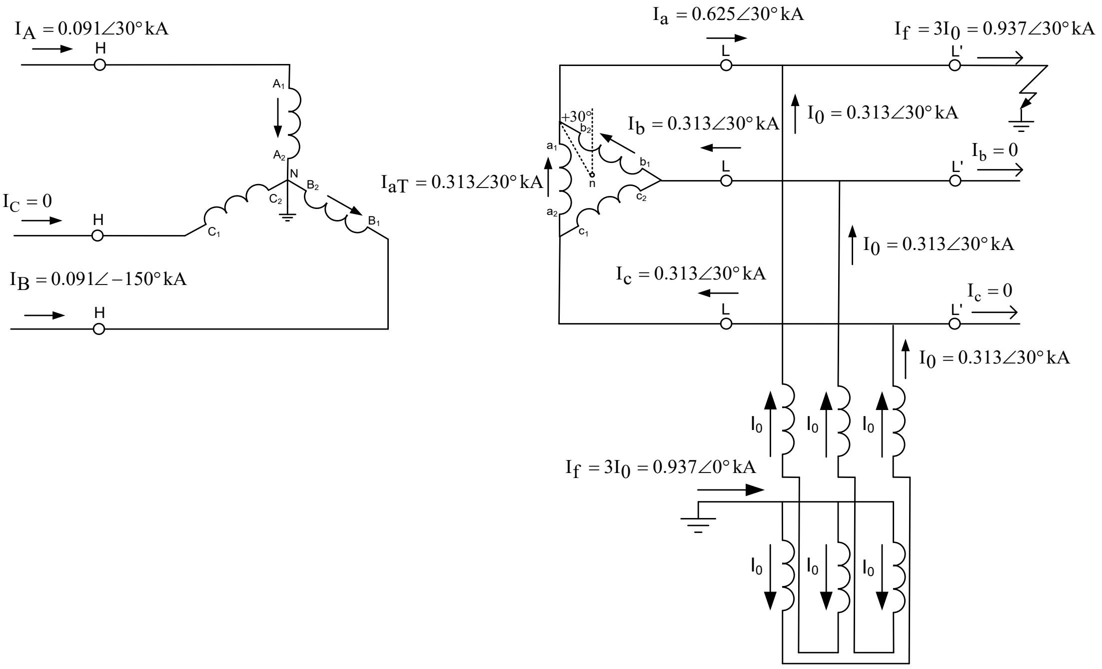
$$I_{A_{\mathrm{pu}}} = \frac{\sqrt{3}\angle 30°}{Z ** + Z_{ET}} = \frac{\sqrt{3}\angle 30°}{(0.985 + 7.438)} = 0.206\angle 30° pu$$

$$I_{A\,line} = (0.206\angle 30° pu)\left(\frac{100MVA}{\sqrt{3}132kV}\right) = 0.091\angle 30°\mathrm{kA}$$

$$I_{B_{pu}} = \frac{\sqrt{3}\angle 30°}{Z ** + Z_{ET}} = \frac{\sqrt{3}\angle - 150°}{(0.985 + 7.438)} = 0.206\angle - 150° pu$$

$$I_{B\,line} = (0.206\angle 30° pu)\left(\frac{100MVA}{\sqrt{3}132kV}\right) = 0.091\angle\text{-}150°\mathrm{kA}$$

18.13.3.3 Phase Current Diagram



19 Appendix A – Protection Grading Example

19.1 Overcurrent Grading Margins

19.1.1 Minimum Grading Margins

19.1.1.1 Case 1:

19.1.1.2 Case 2:

19.1.1.3 Case 3:

19.1.1.4 Case 4:

19.1.2 Ring Systems

19.1.3 Interconnected Systems

19.1.4 Transformer Thermal Limit (I^2t)

19.1.4.1 Low Source Impedance

19.1.4.1.1 System Information

19.1.4.2 Calculation

19.1.4.3 High Source Impedance

19.1.4.3.1 System Information

19.1.4.4 Calculation

20 Appendix B – Selecting Instrument Transformers Examples

20.1 Examples

20.2 Current Transformer Examples

20.2.1 Knee Point

20.2.1.1 Transformer LV CT

20.2.1.1.1 Stability

20.2.1.1.2 Reliability

20.2.1.2 Transformer HV CT

20.2.1.2.1 Stability

20.2.1.2.2 Reliability

20.3 IPCT Examples

20.3.1 Ratio

20.3.1.1 HV Star / Delta IPCT

20.3.1.2 HV Star / Delta IPCT With Existing LV IPCT

20.3.2 Knee Point

20.3.2.1 Transformer HV In-Zone Fault

20.3.2.1.1 Main CT Saturates

20.3.2.1.2 Main CT Does Not Saturate

20.3.2.2 Transformer – LV Through Fault

20.3.3 Resistance

20.3.3.1 Example 1 Collier T1

20.3.4 Zero Sequence Filtering

20.3.4.1 IPCT Required

20.3.4.2 IPCT Not Required

20.3.5 IPCT Ratio Effect on Transformer Bias Setting

20.3.5.1 Ratio Adjusted

20.3.5.1.1 Top Tap

20.3.5.1.2 Bottom Tap

20.3.5.2 Ratio Not Adjusted

20.3.5.2.1 Top Tap

20.3.5.2.2 Bottom Tap

20.4 VT Examples

20.4.1 Shunt Resistor Calculation

20.4.1.1 Insignificant Secondary Burden

20.4.1.2 Significant Secondary Burden

20.4.1.3 Shunt Resistors Not Required

21 Appendix C – Ordering Interposing Current Transformers Example

21.1 Ordering IPCTs

21.1.1 Interposing CT Specification

21.1.1.1 Project Information

21.1.1.2 IPCT Information:

21.1.1.3 Ordering non-standard IPCTs

21.1.1.4 Standard Metering Class IPCTs

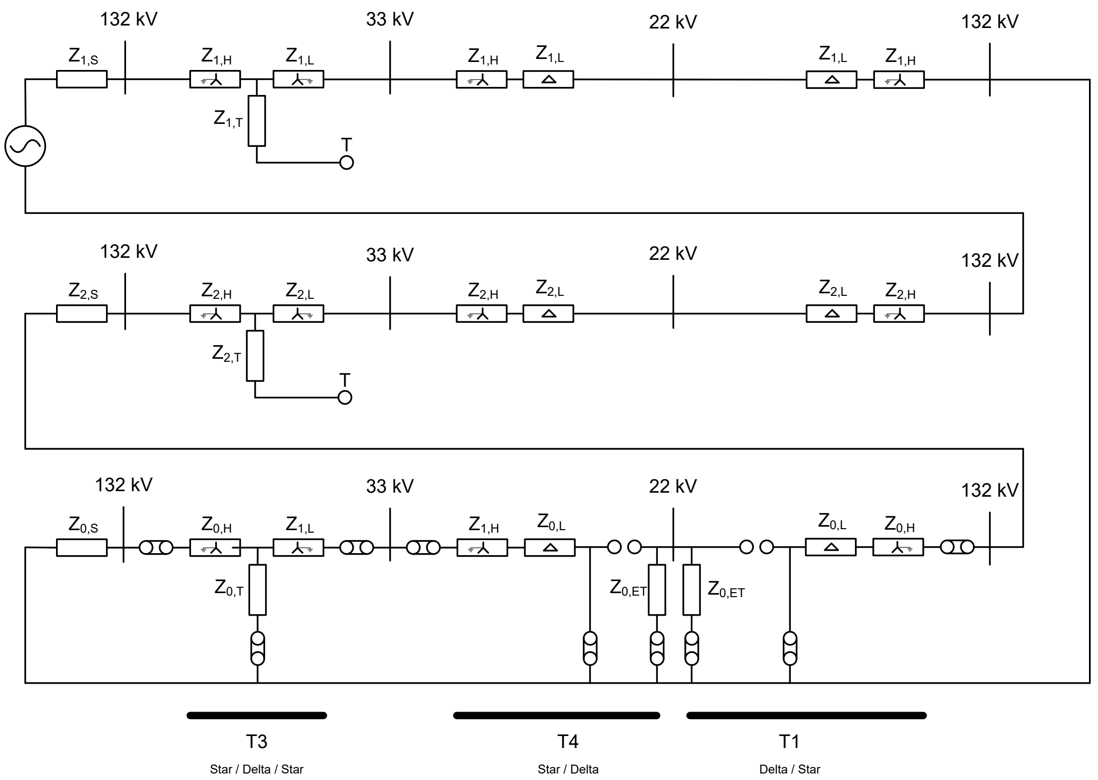
22 Appendix D – Sequence Components & Phase Currents Examples\

22.1 Functional Requirements

Examples in this document show how phase current distribution is derived from sequence components for transformers on the Western Power system.

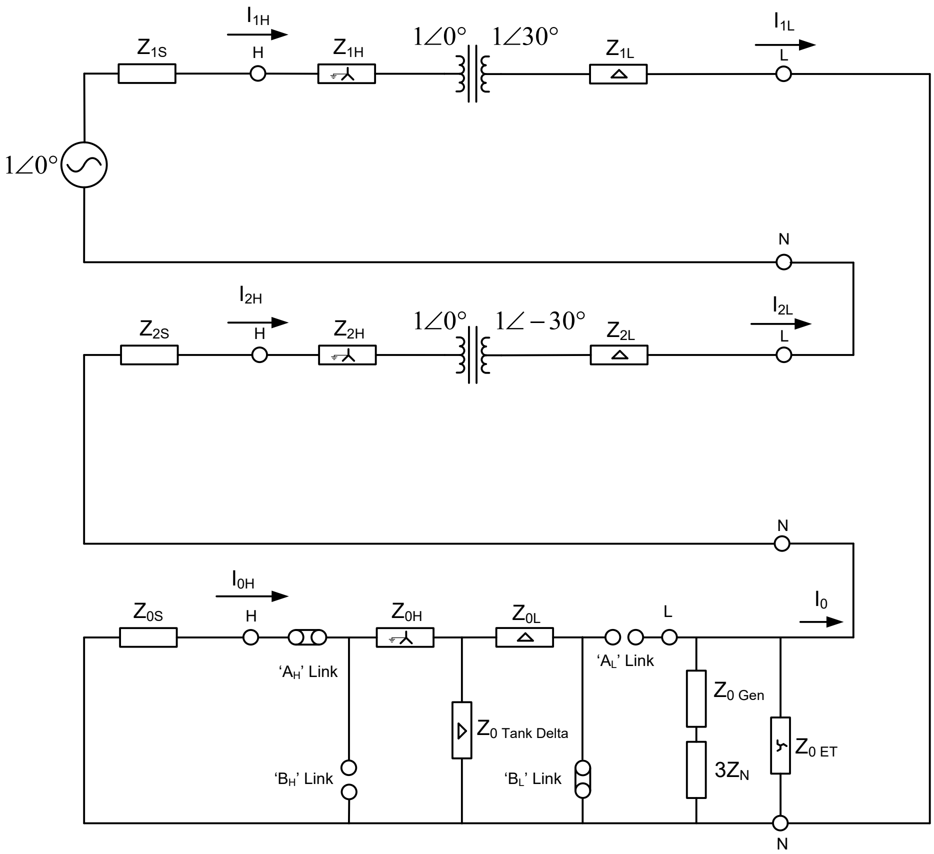
22.2 Examples

22.2.1 Regans



22.2.2 West Kalgoorlie Generator Zero Sequence

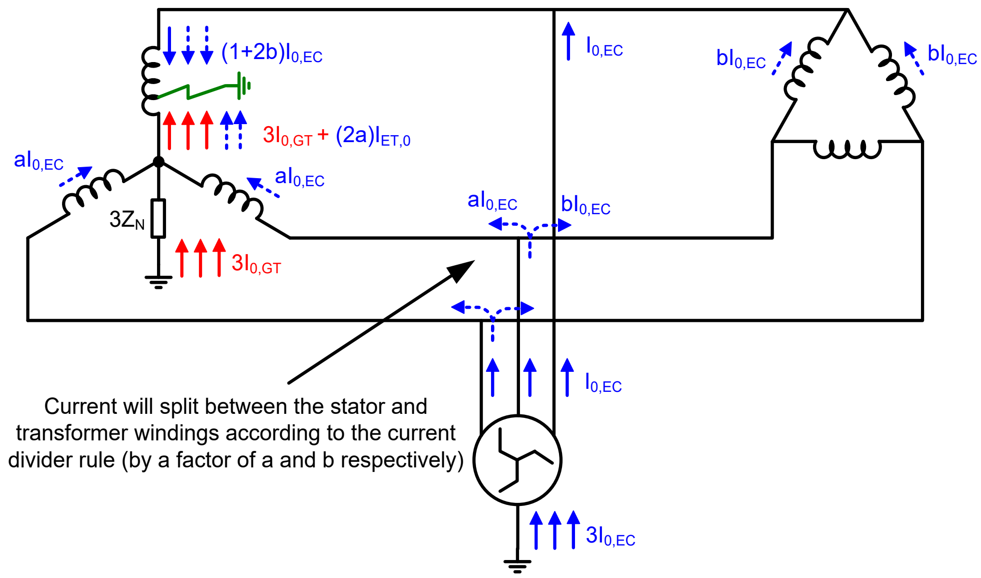
A request was made to move an earthing transformer from an adjacent busbar to the generator LV.



The $3Z_N$ impedance is included in the generator HV neutral to limit earth fault currents in the stator of the generator to typically 10A. Any unbalance above 10A will cause the generator stator earth fault protection to operate.

An earthing transformer put across the LV terminals of the generator in parallel with the $3Z_N$ impedance reduces the fault current through the generator stator further. The ET in parallel with the 3ZN will reduce the total zero sequence impedance and therefore increase the total fault current.

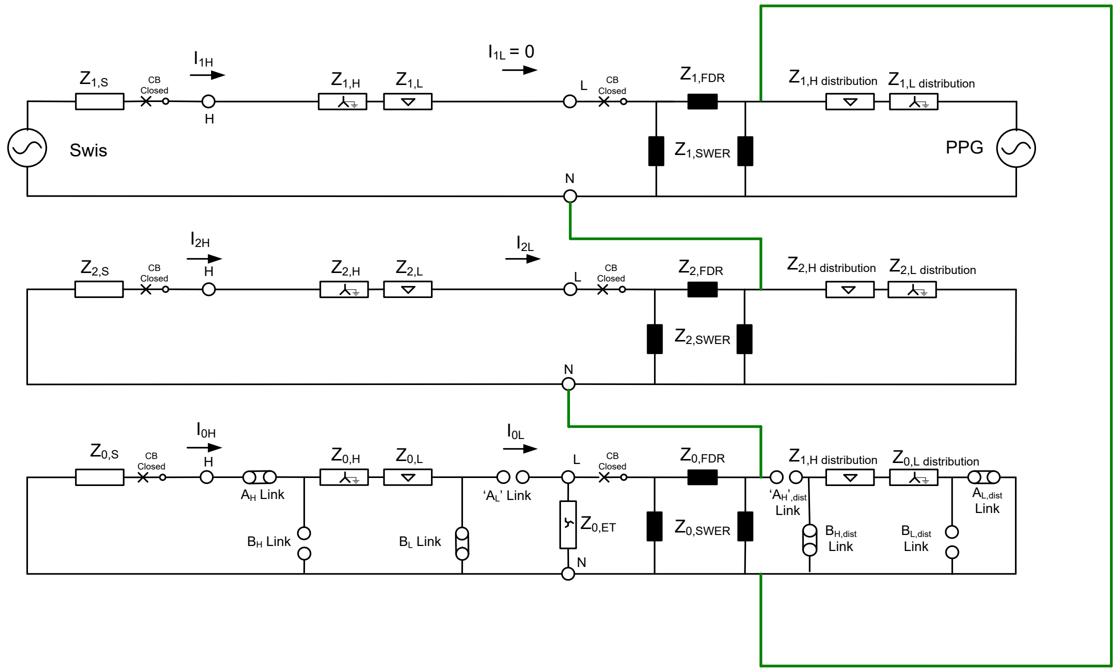
For earth faults within the generator (i.e. from a stator winding to the generator casing or core) the earthing transformer contributes fault current (i.e. $I_{EC,0}$) which flows into the generator stator winding as illustrated below:



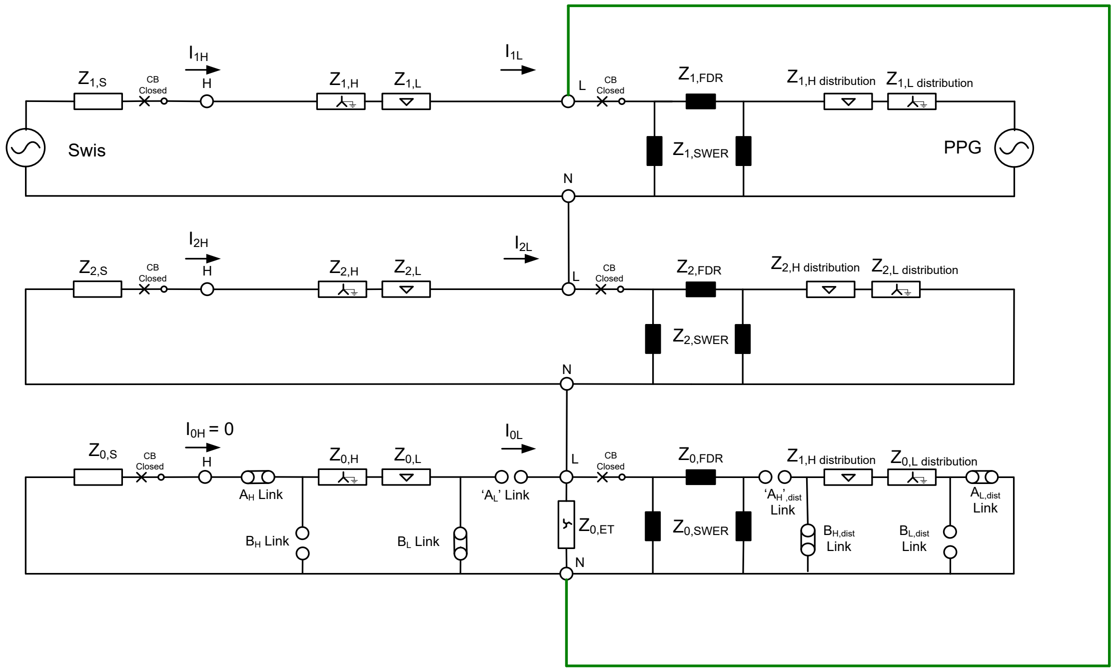
Connecting the earthing transformer across the generator LV terminals is therefore unacceptable.

22.2.3 Distribution Connected Generator

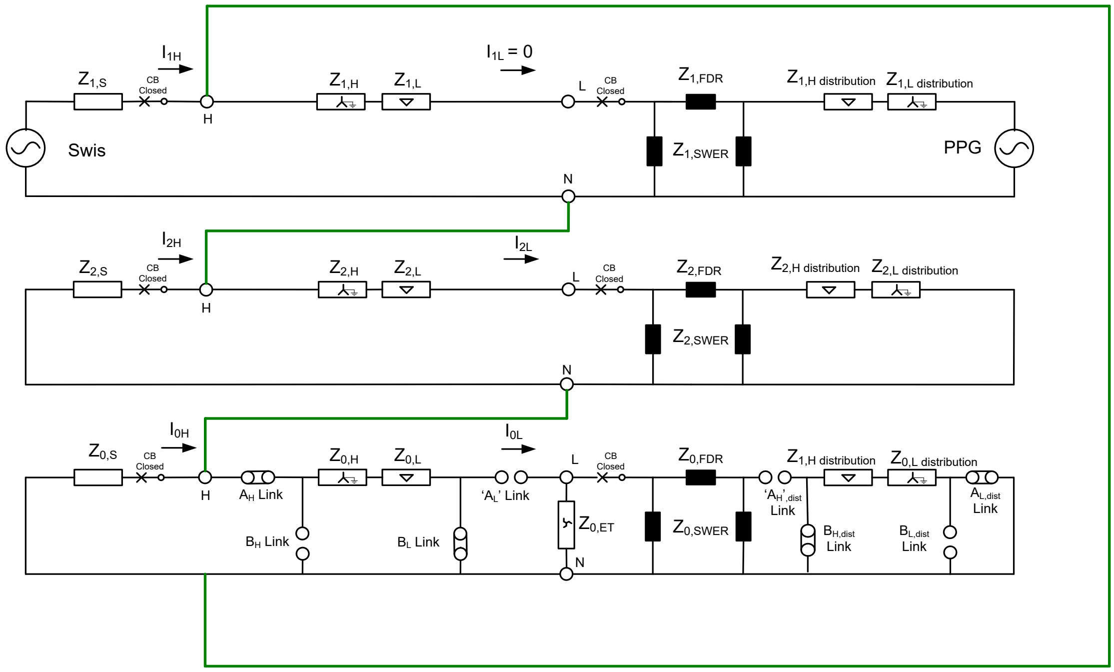
22.2.3.1 System Normal, Earth Fault on Feeder at Generator End



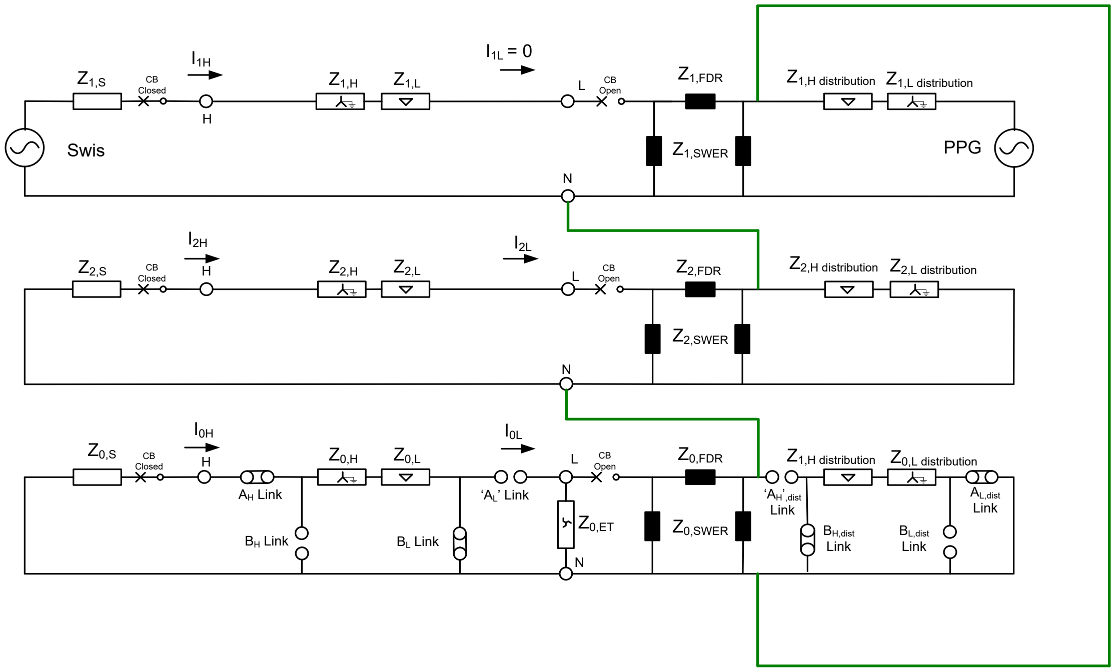
22.2.3.2 System Normal, Earth Fault on LV Terminals



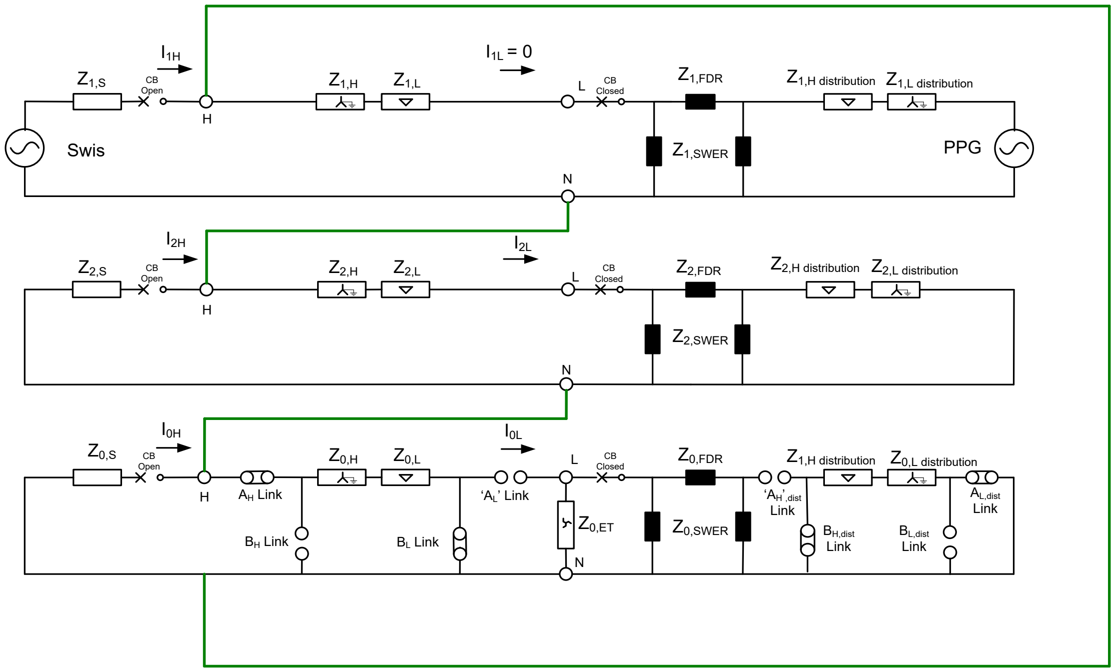
22.2.3.3 System Normal, Earth Fault on HV Terminals



22.2.3.4 PPG Islanded at LV Circuit Breaker, Earth Fault on Feeder at Generator End



22.2.3.5 PPG Islanded at HV Circuit Breaker, Earth Fault on HV Terminals



23 Appendix E – Sensitivity Examples

23.1 Introduction

23.2 Scope

23.3 Functional Requirements

23.4 Examples

23.4.1 Electromechancial and Numerical Relay Error and Risk Comparison

23.4.2 Protection Sensitivity Performance

23.4.2.1 Example 1 System Data

23.4.3 Effect of Tap Changer

23.4.3.1 Case 1: Mount Barker T1

23.4.3.1.1 Configuration

23.4.3.1.2 Study

23.4.3.1.3 Discussion

23.4.3.2 PSSE Study

23.4.3.3 Case 2: Padbury T3

23.4.3.3.1 Configuration

23.4.3.3.2 Study

23.4.3.3.3 Discussion

23.4.3.3.4 PSSE Study

24 Appendix F – IEC Protection Device Address Naming Convention

24.1 IEC Protection Device Address Naming Convention

This section covers the convection for naming 61850 Protection IEDs Addresses within a Substation environment. This address is used in the protection settings as well as found on the protection schematics. Hence alignment between the two names is important to minimise unnecessary confusion.

The naming convections are based on IEC/ISO 81346 – 2.

24.1.1 Voltage Level

The first prefix will define the voltage level.

Prefix	Description
E*	8 = 132kV, 7 = 66kV, 5 = 22kV, 3 = 11kV, 2 = 6.6kV 0 = 415V AC

24.1.2 Schematic Element

The second prefix will define the most relevant subclass that the IED is being used for. Below are the commonly used schematic elements used by Protection Design.

Prefix	Description
Q**	** = Circuit number
W*	* = Busbar number
QK*	* = goose manager device where * corresponds to the busbar that the goose manager is monitoring.
FG*	* = Logic Controller (use the number of logic controllers on the cubicle)
FY*	* = General protection device (starting chronologically from 1) not associated with a particular circuit number / busbar number that does not fit one of the above categories. Examples of use of this prefix would include System Synchronises and voltage selection relays.

24.1.3 Protection Number

The third prefix will define the Protection number which should match the battery number.

Prefix	Description
F*	1 = Protection 1, 2 = Protection 2

24.1.4 Device number

The fourth prefix is a unique number (starting chronologically from Z1) used to differentiate for more than one protection relay at the same protection location and battery number. The Z prefix has been added to differentiate between a 61850 numerical relay with protection settings.

Prefix	Description
Z*	* = protection IED unique number 1 = Primary protection relay (example TX IED) 2 = Second protection relay (example TX RIO) 3 = Third protection relay (example TX AVR) 4 = forth protection relay (example TX MVR) Etc.

24.1.5 Inter site GOOSE Schemes

When a protection IED is used to communicate using GOOSE messaging across multiple substations, a Substation Identifier is to be appended before the voltage level. If a protection IED is only being used to GOOSE locally within a substation this prefix is not required. Note, this prefix is only required when using GOOSE between multiple substations, not for MMS applications between sites. This is because in GOOSE applications, the IEDs reside in the same SCD file, whilst in MMS applications they reside in separate SCD files.

Prefix	Description
***	*** = Substation Code (Example ENT)